FITCHBURG GAS AND
ELECTRIC LIGHT COMPANY
A Unitil Company

Update of 2003 Integrated Gas Resource Plan

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I. UPDATE AND OVERVIEW

UPDATE

On May 9, 2003 Fitchburg Gas and Electric Light Company ("FG&E" or the "Company") filed its 2003 Integrated Gas Resource Plan ("IRP") with the Department of Telecommunications and Energy ("DTE" or "Department"). The IRP filing was docketed as D.T.E. 03-52 and on July 31, 2003 the Department issued its first set of information requests in the proceeding. Subsequent to discussions with Department staff in August 2003, FG&E requested, and the Department granted, a modification in the procedural schedule and permission to file an updated 2003 IRP on or before October 31, 2003. The reasons for the update are to correct certain data sources used in the development of the original forecast of FG&E's firm sendout requirements, and to reflect the effect of such changes, if any, on the resource plan. In developing the revised forecast the Company and its consultant, Concentric Energy Advisors ("CEA")[1] also updated historical data that was not available at the time of the initial filing, corrected certain spreadsheet errors discovered during the preparation of the revised forecast, and updated the weather normalization process for more recent degree day data.

To facilitate the review of the updated 2003 IRP, the Company and CEA have provided a summary and comparison of the updated results relative to the original 2003 filing. Specifically, CEA has compared the updated 2003 IRP normal year, design year and design day forecast results to the original IRP forecast. In addition, this section of the report reviews and describes certain data corrections and analysis adjustments incorporated into the 2003 updated IRP.

CEA incorporated numerous enhancements in the updated 2003 IRP that are described below. In aggregate the impact of these enhancements on the projected normalized total company throughput was minimal. Specifically, the updated forecast for Normal Throughput is approximately 2-4% higher than the original forecast, as shown in Table A.

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1 On October 1, 2003, Commonwealth Energy Advisors became Concentric Energy Advisors.

Table A: Total Company Throughput* - Normal

	Updated IRP (Dth)	Original IRP (Dth)	Difference (Dth)	Difference %
2003	2,371,907	2,333,718	38,189	1.64%
2004	2,412,302	2,344,124	68,179	2.91%
2005	2,436,099	2,352,569	83,530	3.55%
2006	2,443,416	2,361,883	81,534	3.45%
2007	2,457,421	2,368,399	89,023	3.76%
CAGR	0.89%	0.37%	-	0.52%

* Total Company throughput is total end use consumption + lost and unaccounted for

The main driver of the projected increase in throughput is a higher forecasted growth rate in the updated 2003 IRP than in the original filing. In the original filing, CEA forecasted a compound annual growth rate of 0.37%, while in the updated IRP the forecasted compound annual growth rate is 0.89%.

Similar to the normal throughput forecast discussed above the revised design year forecast is approximately 2-4% higher than the original design year forecast. Table B summarizes the results from the updated and original filings.

Table B: Total Company Throughput - Design Year (1 in 30)

	Updated IRP (Dth)	Original IRP (Dth)	Difference (Dth)	Difference %
2003	2,560,603	2,511,002	49,601	1.98%
2004	2,600,770	2,517,689	83,081	3.30%
2005	2,622,575	2,522,380	100,195	3.97%
2006	2,626,233	2,528,197	98,036	3.88%
2007	2,637,445	2,531,077	106,367	4.20%

Finally, CEA will address the design day forecast. In the original 2003 IRP, CEA based its analysis on the highest degree day in each January from 1983 to 2002. In the updated 2003 IRP, CEA expanded the data set to include the highest degree day in any winter month (December through February)[2] in order to capture winter peak days which do not occur in January. The design day results for the updated and original forecasts are shown in Table C below.

2 One observation occurred in March.

Table C: Design Day (1 in 30) Throughput

	Updated IRP (Dth)	Original IRP (Dth)	Difference (Dth)	Difference %
2003	22,025	22,098	(73)	-0.33%
2004	22,133	22,220	(87)	-0.39%
2005	22,241	22,342	(101)	-0.45%
2006	22,349	22,464	(115)	-0.51%
2007	22,457	22,586	(129)	-0.57%

As shown in Table C, the differences in the design day forecast are not material.

As summarized below, data corrections and analysis adjustments in the updated 2003 IRP fall into two general categories: (i) Independent Variables; and (ii) Historical Data.

Independent Variables

As noted in the original 2003 filing, the selection and use of independent variables is one of the most critical elements in developing the regression equations. In the updated 2003 IRP, CEA made certain adjustments to the existing data set and expanded the set of independent variables.

The first adjustment was to update the Natural Gas Price forecast variables. The original 2003 IRP filing utilized a February 2000 fuel price forecast developed by WEFA-Global Insights. The updated 2003 IRP utilized a more recent fuel forecast (i.e. December 2002) which was also developed by Global Insights.

The second adjustment was the inclusion of three additional independent variables in the data set. In the updated 2003 IRP, CEA included Output, Disposable Income, and Household variables. These variables were included in order to provide a more comprehensive set of variables from which to develop the regression equations. All three variables were provided by Global Insights, the same provider of all other independent variables, and are defined as follows:

Output – Value of Production.

Disposable Income – Amount of income available for inessential consumption after essential costs have been met.

Households – Number of households.

The final change to the independent variables pertained to the application of inflation indices. In the original filing, the Consumer Price Index ("CPI") was applied to independent variables associated with residential forecasts, while the Producer Price Index PPI was applied to independent variables associated with commercial and industrial forecasts. In the updated 2003 IRP, the inflation factors were applied to the independent variables depending on the customer segment receiving the price signal. CPI was applied to all independent variables that are generally referred to as consumer prices and PPI was applied to producer price variables. Therefore, in the updated 2003 IRP, the only variables to which the Producer Price Index ("PPI") was applied are the price of residual oil, and the price of industrial gas. All other variables were inflated using the CPI.

Historical Data

During the update process, four issues associated with historical data used in the original IRP were identified and addressed.

The first issue was associated with 1999 data. The original filing utilized 1999 customer and sales data that were incorrectly mapped to the pre-disaggregated rate classes (Residential, GS-1, and GS2). The updated 2003 IRP filing utilized properly mapped 1999 data.

The second data issue was a data update. At the time that the analysis was conducted for the original 2003 IRP, the full year of 2002 calendar weather data was not available, and not reflected in the weather normalization process. Since weather data is now available for 2002, the updated 2003 IRP includes 2002 data in the weather normalization process.

The third data issue was a spreadsheet error. An incorrect cell reference caused reported actual volume data for 2002 to be calculated incorrectly. Since the original 2003 IRP did not use the 2002 data to develop the regression equations, that data error did not affect the results of the forecast. That notwithstanding, the error was corrected in the updated forecast.

The final data issue is associated with the historical billing data. The Company corrected certain billing data to reflect billing errors in the data series prior to CEA performing the regression analysis. For example, the Company corrected for a large customer that had registered uncharacteristically high consumption in January and negative consumption in March. The data was corrected by allocating a portion of consumption volumes from January to March, thus providing a more accurate consumption profile.[3]

After having made the changes and modifications described above, CEA respecified the customer class forecasts. This resulted in a change to the regression equations developed for the original filing. The impact of the new equations was a 2% to 4% increase in projections for normal and design year throughput, this increase however did not affect the Company's Resource Assessment. Specifically, as discussed in Section III - Resource Assessment, the updated forecast results were integrated into the resource analysis as shown in Tables 3.4, 3.5, and 3.6. Because the Company's gas supply portfolio provides the ability to swing up or down, the Company is able to accommodate the relatively minor change in requirements without modifications to the Resource Plan.

OVERVIEW

The Company's sales, firm transportation and sendout requirements forecast for the planning horizon of 2003-2007, as prepared and supported by CEA, is presented in Section II, Requirements Assessment. FG&E's Resource Planning Guidelines are discussed in Section III, Resource Assessment. A review of FG&E's current portfolio of capacity and commodity resources follows in this Section, along with analyses demonstrating the Company's ability to meet demand requirements under differing design conditions.

FG&E submitted its last IRP to the Department on May 1, 2000 in D.T.E. 00-42. The Department approved the plan in an order issued on January 12, 2001 with a directive that the firm transportation forecast in the Company's next filing be based on (i) actual experience; and (ii) the collection of relevant data and information to appropriately develop the transportation forecast. Fitchburg Gas and Electric Light Company, D.T.E. 00-42 (January 12, 2001) at 11. Section II F, ("Firm Transport") of this filing describes the methodology used in developing the firm transportation forecast in compliance with this directive.

The Department assesses each utility's long-range planning standards, demand forecasting methods and results, and design and normal sendout forecasts in order to

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3 In the original 2003 IRP filing, this issue was identified by the DTE in the DTE's First Set of Information Requests, DTE-1-35.

determine if they are reviewable, appropriate and reliable. A forecast method is reviewable if it "contains enough information to allow a full understanding of the forecast methodology". Id. at 3. It is appropriate if it is "technically suitable to the size and nature of the particular gas company," and it is reliable if it "provides a measure of confidence that the gas company's assumptions, judgments and data will forecast what is most likely to occur." Id. FG&E has designed and developed its IRP to meet the Department's standards. The planning process and forecast methodology are fully described herein, with tabular analyses and flow charts used where appropriate.

The plan demonstrates that the planning standards are appropriate for a company of FG&E's size and that the current resource and supply planning process result in a reliable, flexible and least cost supply and capacity portfolio to meet the forecast demand under normal as well as design day, design year and cold snap scenarios. FG&E continually monitors and refines its resource plans in response to changing market conditions and opportunities, with a goal of maintaining the maximum degree of reliability and flexibility, thus further supporting the appropriateness of the plan. Finally, the reliability of the plan is supported by the reasonableness of the assumptions, methodologies and testing described in the plan. One of the Company's key resource planning goals is to maintain a significant degree of flexibility in the plan as this relates to new resource decisions and the evolving and changing marketplace. This further supports the reliability of the plan.

The current resource portfolio includes pipeline supplies, underground storage, interstate pipeline transportation and local production facilities. FG&E plans to continue to extend its local production agreements. These local facilities include a liquefied natural gas (LNG) storage/vaporization facility and a propane air facility that will provide peaking supply to maintain system reliability. The Company's gas supplies are acquired in the unregulated gas supply marketplace with the goal of maintaining a reliable and flexible supply through acquisitions from diverse supply sources. Underground storage and interstate transportation services are provided by FERC regulated entities with the Tennessee Gas Pipeline Company ("TGP") currently providing interstate pipeline transportation to the FG&E citygate. Savings associated with Department approved DSM program installations are reflected as a reduction to the demand forecast for the Resource Plan and effectively serve as an additional resource in the resource portfolio.

With regard to the current resources, five of FG&E's TGP capacity contracts were scheduled to terminate on January 31, 2004 and the remaining three contracts were scheduled to terminate on March 31, 2004. FG&E's storage contract with Tennessee was scheduled to terminate on March 31, 2004. FG&E was required to provide renewal notification one year prior to the termination dates for the Tennessee contracts and FG&E has recently taken advantage of the renewal options available under the capacity contracts while transferring small increments of long-haul capacity to short-haul capacity where appropriate to improve the economics, diversity and flexibility of the portfolio. FG&E's goal in renewing the TGP capacity contracts was to renew the contracts for staggered periods of two, three and four years while awaiting further guidance from the Department as to Massachusetts LDCs' obligation to continue to plan for and procure necessary upstream capacity to serve all firm customers. FG&E's Capacity Contract Restructuring Plan was approved on April 24, 2003 in D.T.E. 02-85 and is further discussed in Section III D of the Resource Assessment Section, "Marketplace and Short Term Contracting Issues".

The Company has identified in the resource plan areas in which future supply decisions must be made in order to ensure system reliability and in order to ensure that total projected requirements for the FG&E service territory are met. Renewal options under the TGP contracts continue to be one of the major resource planning decision points. The Company's renewal options, it's recently completed RFP process for multi-year LNG service and FG&E's four year contract with Distrigas of Massachusetts LLC ("DOMAC") to provide distribution system pressure support, are further discussed in Section III C (1).

II. REQUIREMENTS ASSESSMENT

The forecast of FG&E's firm sendout requirements over the long-term planning horizon is an integral part of the development of the Company's (IRP). This section of the IRP describes the Company's forecast methodology, assumptions and results over the five year planning horizon covering 2003 through 2007 as prepared and supported by CEA. The Requirements Assessment is organized into the following sections:

- The forecasting process is presented in the Forecast Methodology and Results section.
- The Data Description section identifies the sources of data used to develop the forecast, summarizes the data in terms of growth rates and describes any adjustments made.
- The next section, Weather Normalization, describes the process used to weather normalize historic firm sales by customer class and company-level firm throughput.
- The Customer Class Forecasts section details the forecasting methodology, equations, results and ex-post analysis for each customer class.
- The Normal Year Throughput Forecast section discusses the calculation of the normal firm throughput forecast.
- The Firm Transport section describes three forecast scenarios developed by the Company to identify the portion of total deliveries that are likely to be supplied by third party suppliers.
- The final section, the Planning Standards and Design Forecast section presents the Company's planning standards and associated forecasts.

In addition to the text and tables included in this section, the standard EFSC tables are included in the Appendix along with the statistical documentation and complete forecast results.

A. FORECAST METHODOLOGY AND RESULTS

1. Data Transformation

To provide proper context for the data transformation steps used for this filing, it is important to review and compare the data transformation process in the 2000 IRP relative to the updated filing.

a) Data Transformation used in the 2000 IRP Forecast

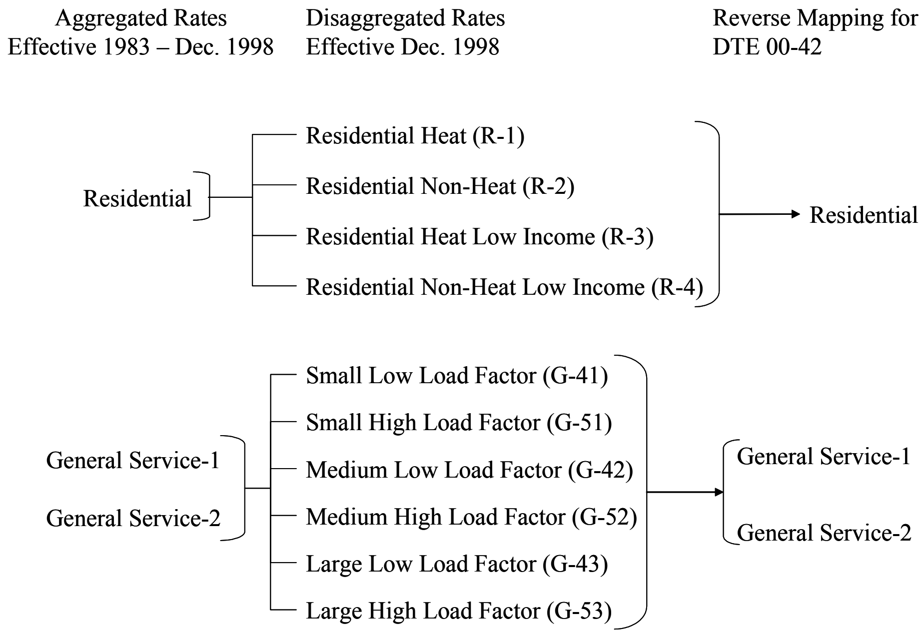
FG&E's Integrated Resource Plan for the 2000-2004 period developed the Company's sendout requirements forecast, supply portfolio and gas transportation arrangements. To develop that forecast, FG&E utilized customer count and system throughput data from 1983 through 1999. The Department's Gas Unbundling order, issued in

D.T.E. 98-32 B, required local distribution companies ("LDCs") to migrate from independent, company-specific rate classes to a standardized set of Massachusetts LDC tariffs and terms and conditions. This policy shift required FG&E to transition its customers from the three rate classes, Residential (R), General Service 1 (GS1) and General Service 2 (GS2) under the Company's prior rate structure to the following ten new rate classes, effective December 1, 1998:

- Residential Heat (R-1)
- Residential Non-Heat (R-2)
- Residential Heat-Low Income (R-3)
- Residential Non-Heat Low Income (R-4)
- Small Commercial and Industrial low load factor (G-41)
- Small Commercial and Industrial high load factor (G-51)
- Medium Commercial and Industrial low load factor (G-42)
- Medium Commercial and Industrial high load factor (G-52)
- Large Commercial and Industrial low load factor (G-43)
- Large Commercial and Industrial high load factor (G-53)

This policy requirement resulted in a change in the data collection processes of FG&E and, as discussed below, required certain modifications in order to produce a consistent historical data set for each customer class. Although FG&E had instituted disaggregated rates as of December 1998, in preparing its 2000 Gas IRP the Company concluded that the data available for each of the ten disaggregated rate classes was insufficient to support individual model development for each rate class. Therefore, utilizing the mapping routine discussed in D.T.E. 00-42, FG&E allocated all the relevant disaggregated data (customer count and sales) into the three previous rate classes in what is in essence a reverse mapping. The conversion was based upon the allocation of sales and customers between the old and new rate structures as shown in workpapers prepared by Management Application Consulting, Inc. filed during the Company's rate case in DTE 98-51. The results of that reverse mapping process then were utilized to develop the forecasts of customer count and associated sales. The following diagram summarizes the mapping/reverse mapping process:

Figure 1: FG&E Data Process Utilized in DTE 00-42



Once the data were mapped into the company specific rate classes (R, GS1, GS2), FG&E developed class level forecasts for customers and sales for the 2000-2004 time period. Total company sales were then developed by aggregating the class level forecasts.

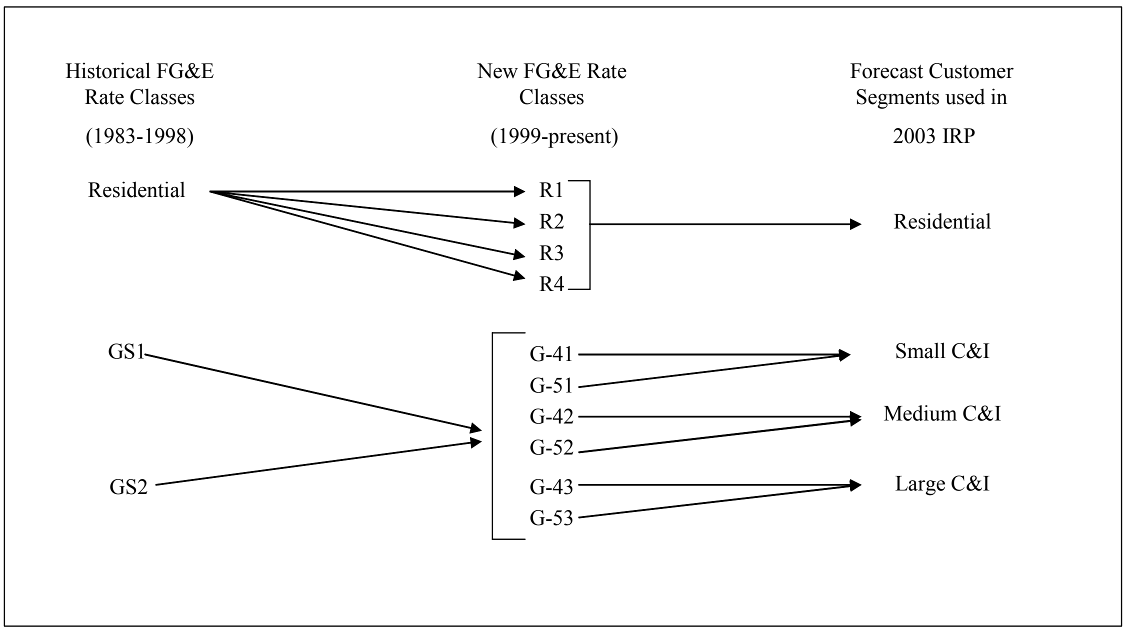
b) Data Transformation for 2003 IRP Forecast

Beginning in 2000, FG&E had largely completed the transition and began to track customer and usage data in the ten new customer classes as opposed to the three rate classes that were used in the 2000 IRP. Therefore, for the purposes of preparing its forecasts, CEA focused on the new rate class designations. In order to develop consistent historical data sets, CEA mapped the historical data into the new customer classes. In essence, the Company has completed the customer mapping and accumulated approximately four years of historical data in the new rate classes, (and this is expected to continue going forward), CEA conducted the reverse of the 2000 IRP mapping process. To prepare the current filing, therefore, the customer count and sales data from FG&E's former (R, GS1 and GS2) customer classes (that were recorded from 1983 through 1998) were disaggregated into the ten standardized rate classes using the customer rate class analysis submitted in Docket No. 98-51. These mapping percentages are provided in the Appendix.

Once the historical data series were developed, CEA aggregated the ten rate classes into four customer class segments for the purposes of developing regression equations and customer segment forecasts. The customer segments were developed based on the total annual consumption level per customer. As such, customers were aggregated as follows:

- All residential customers (R1-R4) were aggregated into the residential customer segment ("Residential");
- G-41 and G-51 customers were aggregated into the small commercial and industrial segment ("Small C&I");
- G-42 and G-52 customers were aggregated into the medium commercial and industrial customer segment ("Medium C&I"); and
- G-43 and G-53 customers were aggregated into the large commercial and industrial customer segment ("Large C&I").

Figure 2: FG&E Data Mapping Process Utilized in the 2003 IRP Filing

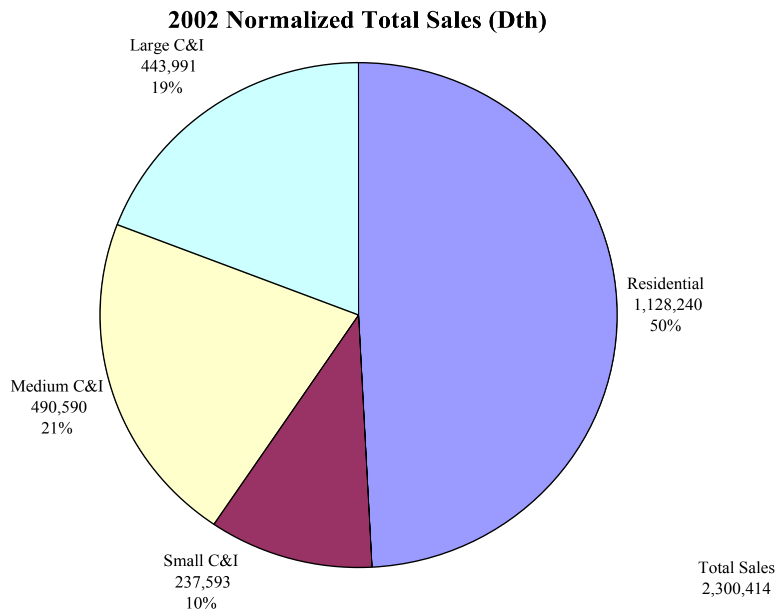


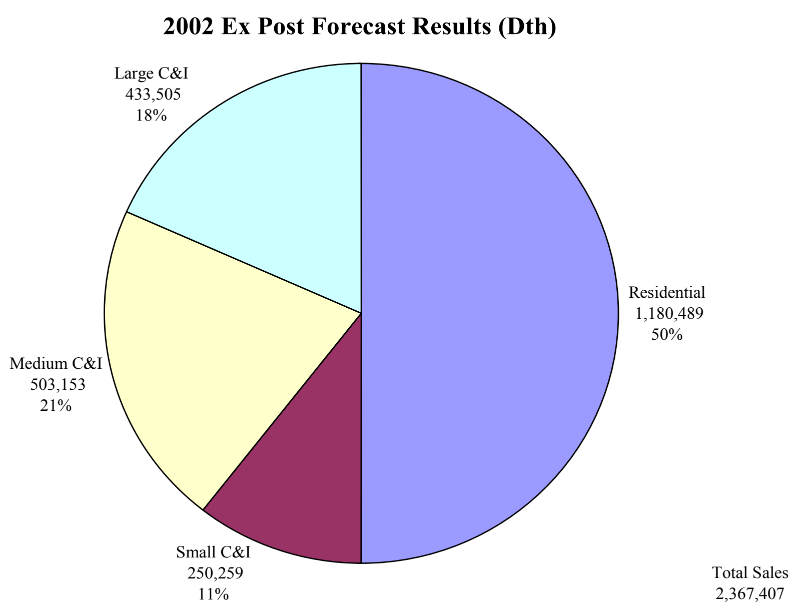
The chart above illustrates the mapping process utilized for both customer counts and sales volumes. Through this process, the data from 1983 through 1998 were mapped from the historical FG&E rate classes into the ten new rate classes, and then aggregated into the four customer segments described above. Please note that the 2000 IRP only mapped 1999 data, and was a reverse mapping as discussed above. Since the 2000 IRP utilized a reverse mapping process for one year of data and the 2003 IRP utilized a mapping process for sixteen years of data, a direct comparison of the 2000 IRP with the 2003 IRP may not be of value. However, since customers will continue to be served under the ten existing rate classes, CEA and the Company determined that it was reasonable to make the transition to the new rate classes and to begin forecasting customer usage in terms of the new rate structures.

It is important to note that some statistical noise is likely to be created whenever a set of historical data collected under one structure are recast into a new structure. In the present case, the mapping of customer usage data from FG&E's old rate structure into its new rate structure was by necessity based on relative customer usage at a given point in time. When the best analytic option available requires such mapping over an historic period spanning 16 years, it is reasonable to expect that certain historic shifts in relative customer usage patterns may be lost. In order to establish a comfort level as to whether the transformed data would yield reliable results, CEA tested the performance of the regression equations on the historical data (backcasting) by customer segment and for total company sales.

The following pie charts illustrate the results of those backcast efforts. The first chart indicates the normalized volumes supplied in 2002 under the four customer segments. The second chart illustrates the backcast volumes for 2002 produced using the regression equations developed for each of the four customer segments. As noted in the charts below, the backcast of the Company's 2002 total sales is not materially different from the actual 2002 total sales. The actual sales experienced in 2002 were 2,300,414 Dth whereas the backcast produced a total normalized sales estimate of 2,367,407 Dth, or a variance of less than 3%. Since the planning process is focused on system-wide demand, and given that future analyses will have the benefit of additional data collected under the new rate structure, CEA determined that conducting the estimation using the transformed data produced reliable results and is appropriate.

Figure 3: Comparison of 2002 Normalized Sales and Backcast Results





2. Forecasting Approach

The FG&E long term firm gas throughput and sendout forecasting process considers the major factors influencing gas consumption in the Company's service territory. Firm

Throughput is defined as total firm sales and firm transportation volumes, including the impact of company use, lost and unaccounted for gas and billing cycle adjustments. Firm Sendout is defined as total firm throughput, net of firm transportation volumes, and as such includes total firm sales and the impact of company use, lost and unaccounted for gas, and billing cycle adjustments. The forecasting process began with the aggregated customer and usage data described above for Residential customers (R1-R4), Small C&I customers (G-41 and G-51), Medium C&I customers (G-42 and G-52), and Large C&I customers (G43-and G-53). These aggregated customer classes are referred to throughout the report as "customer segments".

To generate the forecasts, a regression analysis was conducted on normalized annual total sales and total customers in each customer segment. Regression analysis is a statistical methodology that relates a response variable (dependent variable) with a set of explanatory or predictor variables (independent variables). The goal is to build a model that allows for predictions of the response variable for given values of the explanatory or predictor variables. In this case, the goal was to predict total sales and number of customers by customer segment using various independent variables (e.g. disposable income per capita, employment levels, and population). Total sales volumes include the consumption of FG&E's firm sales customers as well as the consumption of FG&E's firm transportation ("FT") customers over the study period. (The statistical estimation process is described in detail in the Customer Class Forecasts section.) Estimated total customers and sales for each customer segment were summed to produce the Total Company Sales forecast.

Once the Total Company Sales forecast was developed, it was adjusted for company use, lost and unaccounted for and billing cycles in order to develop the total firm throughput forecast. The historical relationship between firm throughput and Total Company Sales was estimated on a statistical basis, and applied to the total firm sales forecast in order to project future firm throughput. Because the forecasts are based on normalized data, the firm throughput forecast represents FG&E's normal throughput forecast. Subsequent to the development of the total throughput forecast, Firm Transportation ("FT") migration scenarios were developed. (Firm Transportation migration scenarios and assumptions are discussed in detail in the Firm Transportation section of the report.) For the purposes of developing firm sendout requirements, the projected throughput volumes were reduced by the Firm Transportation volumes consistent with the FT migration scenarios.

Finally, the Company establishes its planning standards by first calculating the heating degree-days ("HDD") associated with design cold weather conditions of varying probabilities of occurrence (1 in 30 years, 1 in 50 years, and 1 in 100 years). Base load and weather-sensitive components of firm throughput were then identified and the responsiveness of weather-sensitive load was determined. The HDD associated with the different design conditions were applied to these factors in order to produce forecasts of firm throughput associated with each design condition. Pursuant to DTE 00-42, FG&E utilizes the 1 in 30 year design day, and 1 in 30 year design year planning standards. Similar to the process used in determining normal sendout levels under the FT migration scenarios, the design throughput forecasts are reduced for FT volumes based on the assumptions identified in the FT scenarios to yield design sendout forecasts for each design weather condition.

3. Summary of Forecast Results

As is indicated in Table 2.1 below, the updated forecast projects total throughput to increase by approximately 17,500 Dth (or 0.73%) annually over the forecast period under normal conditions. This forecast has been developed at the customer class level, and includes billing cycle adjustments, lost and unaccounted for gas, and company use. Under the base case FT scenario the forecast assumes that in 2003 188,789 Dth, or 8% of total throughput, is associated with transportation customers.

The results for the design year planning standards of 1 in 30 years are also summarized below. As is indicated in the table, under the base case FT scenario, the forecast projects design year throughput of 2,360,311 Dth and transportation of 200,292 Dth in 2003. Those results are described more fully throughout the remainder of the Requirements Assessment section.

Table 2.1: Summary of Forecasts

	Firm Throughput Forecast	Low FT	Base FT	High FT	Low FT	Base FT	High FT
		Normal Firm Sendout			Normal Firm Transport		
2003	2,413,545	2,413,545	2,224,756	2,035,029	-	188,789	378,516
2004	2,450,251	2,450,251	2,255,596	2,058,694	-	194,655	391,557
2005	2,470,177	2,470,177	2,271,626	2,070,377	-	198,551	399,800
2006	2,473,520	2,473,520	2,273,868	2,070,983	-	199,652	402,537
2007	2,483,765	2,483,765	2,281,453	2,074,887	-	202,312	408,878

Design Year (1 in 30) Firm Throughput

	Design Firm Throughput	Low FT	Base FT	High FT	Low FT	Base FT	High FT
		Design Firm Sendout			Design Firm Transport		
2003	2,560,603	2,560,603	2,360,311	2,159,023	-	200,292	401,580
2004	2,600,770	2,600,770	2,394,157	2,185,160	-	206,613	415,610
2005	2,622,575	2,622,575	2,411,774	2,198,109	-	210,801	424,466
2006	2,626,233	2,626,233	2,414,255	2,198,844	-	211,978	427,389
2007	2,637,445	2,637,445	2,422,615	2,203,267	-	214,830	434,177

B. DATA DESCRIPTION

As noted earlier, the demand forecasting process begins with data collection. Historical data were collected from 1983 through 2002; forecast data for explanatory variables were obtained for the period 2002 through 2007. Broadly, three types of data were incorporated into the forecasts: customer consumption data; weather data and; economic/demographic data. Customer consumption data are taken from company records and include historic firm sales and number of FG&E's customers by customer class, historical firm sendout and firm transport data, historic results of demand side management programs, and average price data by customer type. Weather data were taken from the Worcester-Bedford weather database, the database approved for use in FG&E's last three gas IRP filings. Historic and forecast data of various economic and demographic variables were obtained from Global Insights, Inc., (formerly WEFA, Inc.), an economic consulting firm. FG&E has used WEFA as a data source in its past two IRP filings.

Customer consumption data were adjusted to account for changes in the Company's rate structure, including the transition of historical data into the new Residential, Small C&I, Medium C&I and Large C&I classes described earlier. As noted above, prior to the rate change, FG&E offered firm service to three customer rate classes: Residential, General Service Heating Only (GS1) and General Service Heating and Other (GS2). Consistent with the new rate design, FG&E provides firm service to customers under ten rate classes; four residential classes and six general service customer classes. For the purposes of forecasting demand, CEA aggregated the 10 new customer classes into four customer segments, one residential segment and three commercial and industrial segments. The Residential customer segment includes all customers in the R1, R2, R3, and R4 rate classes. The Small C&I customer segment includes the G-41 and G-51 customer classes. The G-42 and G-52 customer classes were aggregated to form the Medium C&I customer segment. Finally, the G-43 and G-53 customer classes were aggregated into a Large C&I customer segment.

The Worcester-Bedford database contains daily heating degree day data from the period 11/01/1965 to present, and is updated regularly with official readings from the two weather stations. The HDD were calculated from a base of 65 degrees. CEA utilized the most recent 35 years of historic weather data from this database in preparing its long term sales and sendout forecasts. The weather data were used (i) to normalize historic class sales as well as company throughput, and (ii) develop the Company's planning standards and design year sendout and peak day requirements.

Forecast data that provide key measures of economic activity and demographic factors that might influence customer counts and consumption behavior were acquired from Global Insights, Inc. The files contain annual data from 1983 through 2001 (referred to herein as the "historic period") and annual forecast data from 2002 through 2007. The data include fuel prices, employment, disposable income, population, and housing statistics specific to Worcester County or the Commonwealth of Massachusetts. Global Insights, Inc. also provided forecasts of the Consumer Price Index ("CPI") and Producer Price Index ("PPI"). The CPI was used to convert nominal dollar values related to consumer prices to real dollars, and the PPI was used to convert nominal dollar values related to producer prices to real dollars. Table 2.2 summarizes the economic and demographic data, indicating code names used in regression equations.

Table 2.2: Economic and Demographic Variables Provided by Global Insights, Inc.

Code Name	*Variable Description*	*Inflation*	*Region*
RGAS	Real Price of Gas to Residential Customers	CPI	FG&E/ Mass
CGAS	Real Price of Gas to Commercial Customers	CPI	FG&E/ Mass
IGAS	Real Price of Gas to Industrial Customers	PPI	FG&E/ Mass
DISOIL	Real Price of Distillate Oil	CPI	Mass
RESOIL	Real Price of No. 6 Residual Fuel Oil	PPI	Mass
POP	Population	N/A	Worcester
MANEM	Manufacturing Employment	N/A	Worcester
SVCEM	Service Sector Employment	N/A	Worcester
NMEMP	Nonmanufacturing Employment	N/A	Worcester
DINCPC	Disposable Income Per Capita	CPI	Worcester
DISINC	Disposable Income	CPI	Worcester
OUTPUT	Value of Services	CPI	Worcester
HHOLD	Households	N/A	Worcester
HSTOCK	Housing Stock	N/A	Worcester
HHSIZE	Household Size	N/A	Worcester
HSTART	Housing Starts	N/A	Worcester

The natural gas price data used in the demand forecasts is a hybrid of historic Company data and price forecasts prepared by Global Insights, Inc. The historic natural gas price data represent actual natural gas prices by FG&E customer segment (residential, commercial and industrial) over the historic period. The forecast price data is developed by applying the growth rates of Global Insights's forecasts for residential, commercial and industrial natural gas prices for Massachusetts to the company-specific historic natural gas prices.

Because there are currently no new gas marketing programs in place for FG&E there is no need to separately add the forecasted impact of such programs to the econometric forecast. Finally, the Company is aware of the potential for the addition of a significant new customer in FG&E's service territory in the forecast horizon. The forecast and supply plan do not reflect this potential new customer, because of uncertainty regarding the customer's plans and the nature of the service to be provided. If and when the specific characteristics of this new load are determined, FG&E will plan separately for this load through the use of the guidelines specified herein, where applicable.

C. WEATHER NORMALIZATION

Gas sales and throughput requirements are heavily dependent upon weather conditions, which can vary significantly on a daily, monthly and annual basis. Thus, historic monthly sales and throughput were standardized (i.e., weather normalized) for aberrations in weather conditions before being used in long term gas forecasting and supply planning. The weather normalization process is described below.

Before class sales can be weather normalized, historic calendar based heating degree-day data need to be adjusted to reflect the timing of customer billing cycles. Since FG&E customer meters are read at a steady rate each working day of the month, consumption (and thus HDD) during the early days of the prior month and late days of the current month have little impact on sales recorded in the current month. In contrast, consumption during the late days in the prior month and the early days in the current month have a significant impact on sales recorded in the current month.

The approach utilized in this filing to adjust for the effects of billing cycle is consistent with the approach used in FG&E's 2000 IRP filing. The days of consumption that affect metered sales in the billing month were summed and used to develop a weighting distribution to attribute calendar consumption to billing cycle data[4]. Historic HDD data from December 1983 through December 2002 were then adjusted for billing cycles by applying the weighting distribution discussed above to daily HDD data. In addition, the weighting distribution was applied to the average daily HDD observed over the 35-year history of the weather database to establish normal billing cycle HDD. The difference between actual and normal billing-cycle-adjusted HDD each month then was used in the weather normalization calculations. Class deliveries were normalized by identifying the weather-sensitive portion of deliveries for each class and identifying the variance between the weather-sensitive deliveries by class and the deliveries that would have occurred if HDD had been normal.

The calculation was performed using the following six step approach:

---

4 The weighting distribution allocates calendar HDD over the course of the month as follows: Day one: 97% to the current month, 3% to the subsequent month. Day two: 94% to the current month, 6% to the subsequent month, and so on.

- Average use per customer in each class is calculated each month.
- Average base load (consumption not sensitive to weather) per customer in each class is taken as the lowest monthly average use over the course of the year[5].
- Average weather-sensitive use per customer is calculated by subtracting base load use per customer from the average use per customer.
- Next, weather-sensitive use per customer per HDD is computed each month by dividing average weather-sensitive use per customer by actual HDD.
- The weather-sensitive use per customer per HDD is then multiplied by the difference between the actual HDD and normal HDD to produce the normalization adjustment per customer.
- The normalization adjustment per customer is then multiplied by the number of customers to produce the weather normalization adjustment each month.

An example of the model used to normalize sales is included in the Appendix.

D. CUSTOMER CLASS FORECASTS

1. Introduction

While the model specification and development process is discussed in detail throughout the report, a general overview of the methodology used is provided below. This general overview includes a discussion of Data Sources and Issues; a review of the Equation Specification and Development process; and a summary of the Forecast Development process.

Data Sources and Issues

- The regression equations were developed using historic annual calendar year data from 1983 through 2002.
- The use of annual data removes any issues related to seasonality and to the aggregation of customers having low annual load factors with customers having high annual load factors.
- Weather data were not incorporated into the equations as explanatory variables, as all throughput data were weather normalized prior to estimation.

Regression Equation Specification and Development

- Separate econometric regression equations for number of customers and for total sales were developed for each of the four customer segments: Residential, Small C&I, Medium C&I, and Large C&I.

[5] Base loads were almost always determined by usage in August, as August usually has the lowest consumption.

- As appropriate, the number of customers and sales by class were regressed against the economic and demographic variables discussed in the Data Description section.
- All volumetric equations were estimated in logarithms using ordinary least squares (OLS) regression. Parameter estimates of independent variables estimated in logarithms represent percent changes in the dependent variable relative to percent changes in the independent variable. CEA attempted to estimate volumes on an average use per customer basis and on a total sales basis for each customer segment. In the case of each customer segment, the equations specified for total sales were of greater statistical significance than those specified for use per customer, and therefore were used to develop the demand forecasts.

Forecast Development

- The regression equations were applied to the annual forecast data provided by Global Insights, for 2003 through 2007 to compute the forecasts.
- Finally, the customer segment forecasts were aggregated to produce a total Company demand forecast.

2. Modeling of Forecast Equations

Although the final equation of each the eight models is unique, a common modeling process was used to develop the regression equations. In general, the pre-estimation model specification process was followed by an iterative process of specification and refinement. Finally, the forecast was generated and an ex post forecast was calculated and used to assess the model robustness. The model specification and development process is discussed in more detail below.

1. Determine "*A Priori*" Expectations. *A priori* expectations are theoretical relationships that one would expect to exist between certain variables based on economic theory or professional judgment. For example, as the housing stock rises, we would expect residential customers also to increase. In this step, therefore, the objective is to identify those independent (i.e., predictor) variables that are most likely to influence the dependent variable.

2. Examine Variable Correlation. The degree (0% to 100%) and direction (+/-) of correlation between potential independent variables and the dependent variable can indicate whether expected relationships (as determined by the *a priori* expectation step) are borne out in the data. Reviewing correlations among likely independent variables

also can help identify variables that may be collinear and, if collinearity does exist, suggest suitable proxy variables.

3. Specify and Estimate Initial Forecasting Equation. Using a priori expectations and information about variable correlation, from steps 1 and 2, an initial forecast equation is specified and estimated.

4. Connect Parameter Estimates to Theory. The statistical output from step 3 is reviewed to verify that the sign and magnitude of parameter estimates of independent variables reflect plausible underlying theoretical relationships to the dependent variable. A strong statistical relationship may exist between two variables, but if the parameter estimates are inconsistent with theory it is important to consider how the independent variable is interacting with other independent variables in the equation. While it is possible that such a result is a signal of missing data, it is also possible that it is a sign of the relative explanatory capability of the variables used in the equation. Sometimes statistical relationships differ from *a priori* expectations yet still reflect plausible underlying relationships.

5. Verify Statistical Tests. A number of statistical tests need to be satisfied before we can accept the parameter estimates of independent variables and rely upon a regression equation for forecasting purposes. These tests include the t-test, the F-test, the R-squared and the Durbin Watson test. Those tests assess the statistical significance of the variables used (both separately and jointly), the explanatory power of the equation as a whole, and properties of the residuals respectively[6]. A brief description of each statistic and how the statistic is used for model evaluation is provided below.

   - The *t-statistic* of an independent variable tests whether that specific variable explains a significant level of variation in the dependent variable when other independent variables are included in the model. Only independent variables with significant t-statistics are included in the final equations.
   - The *F-statistic* is a joint t-test on all independent variables in a regression equation and thus tests how well a certain set of independent variables model the dependent variable. The F-statistic may be used to choose between alternative equations.

---

[6] Residuals are the differences between the values of the dependent variable fitted by the regression model and the actual observed values of the dependent variable for each observation of the sample.

- The *R-squared* and *Adjusted R-squared* measure the overall goodness of fit for the regression model[7]. The closer the R-squared value is to 1, the better the fit of the model. Similar to the F-statistic the R-squared can also be used to choose between alternative models.
- The *Durbin-Watson statistic* (DW) is a generally accepted test for serial correlation among residuals. When estimating regression equations one must verify that the residuals are not correlated over time (also known as serial correlation). The critical value for DW statistics depends on the number of independent variables and the number of historical data points used in the analysis. Any DW value below the critical value indicates that serial correlation is present in the residuals. When serial correlation does exist it can be corrected using autoregression time series modeling techniques. Autoregression models are similar to regression models; however an autoregressive term is included to address the correlated residuals. Adding an autoregressive term to the regression equation requires recalculating the coefficients of the independent variables in an iterative fashion until the serial correlation in the residuals is removed. This iterative technique is known as the Prais-Winsten transformation. If certain equations exhibited serial correlation as measured by the DW statistics, the Prais-Winsten autoregression technique was used to correct and improve the equation.

6. Re-specify the Forecasting Equation. Based upon the findings in Steps 4 and 5 above, the models may need to be re-specified over several iterations before satisfactory statistics are observed.

7. Generate Forecast and Ex-post Forecast. When each final equation is determined, the regression equation is applied to forecast values of the independent variables to generate the forecast. In addition, the equation is applied to five years of historical data to create an ex-post forecast. Ex-post forecasts are compared to actual data to assess the robustness of the forecast equation.

The remainder of this section describes the application of the seven step process described above to the specification of customer and volume equations for each of the four customer segments. Each of the customer segments below includes:

- A review of the actual customers and volumes for the period 1983-2002;
- A summary of independent variables, a priori expectations and associated variable correlations;
- A description of the final regression equations utilized;

7 Adding variables to a regression model, even arbitrarily, will automatically increase R-squared. The Adjusted R-squared accounts for the number of independent variables in a regression equation, and is preferred when more than one independent variable is modeled.

- Model performance as indicated through a five year backcast process; and
- Forecast results for the period 2003-2007.

3. Residential Customer Segment

As discussed above, all four residential rate classes were collapsed into one segment for forecasting purposes. Therefore, the residential class segment forecast includes the customers and demand in all four residential rate classes, specifically: Residential Heat (R-1), Residential Non-Heat (R-2), Residential Heat Low Income (R-3) and Residential Non-Heat Low Income (R-4).

As can be seen in Table 2.3 below the residential customer data set has had three distinct growth patterns. In the early years of the data set, 1983 through 1990, FG&E experienced a 0.6% annual growth in residential customers. From 1990 through 1995, there was a decline of 1.25% annually, and from 1995 through 2002 there was a slower decline of 0.23% annually. Over the entire period from 1983 to 2002 the annual growth rate has been -0.2%. Residential gas demand follows a similar pattern. From 1983 through 1989 FG&E experienced growth in residential customer demand of 0.8%, after which time demand begins to decline at an average annual rate of 1.0% per year. Similar to residential customers, residential gas demand has a negative annual growth rate of -0.4% over the entire historical period.

Table 2.3: Historical Residential Customer Data

	Residential Customers	Residential Volume (Dth)
1983	13,826	1,227,057
1984	13,880	1,267,253
1985	13,877	1,245,917
1986	14,010	1,259,198
1987	14,173	1,267,933
1988	14,254	1,260,391
1989	14,367	1,285,742
1990	14,399	1,265,612
1991	14,385	1,220,950
1992	14,191	1,207,353
1993	14,070	1,204,152
1994	13,787	1,221,045
1995	13,522	1,189,580
1996	13,492	1,234,380
1997	13,429	1,197,519
1998	13,366	1,226,715
1999	13,303	1,183,993
2000	13,289	1,173,251
2001	13,357	1,131,008
2002	13,309	1,128,240
'83-'02 CAGR	-0.2%	-0.4%

As discussed in the next section, the pattern and timing of the trends experienced in the historical residential customer data was somewhat difficult to explain using the available economic and demographic variables.

a) Residential Customer Regression

The number of residential customers (RCUS) was expected to be primarily driven by changes in the population, housing stock and employment levels. As more people live and work in the service territory, the number of customers would be expected to increase, however given the slow but steady attrition in customers and volumes as discussed above, a negative coefficient would not be unexpected. The correlation matrix provided in Table 2.4 lists the variables considered, their correlation to residential customers and their correlation to each other. All variables are listed by code name as described in the Data Description section.

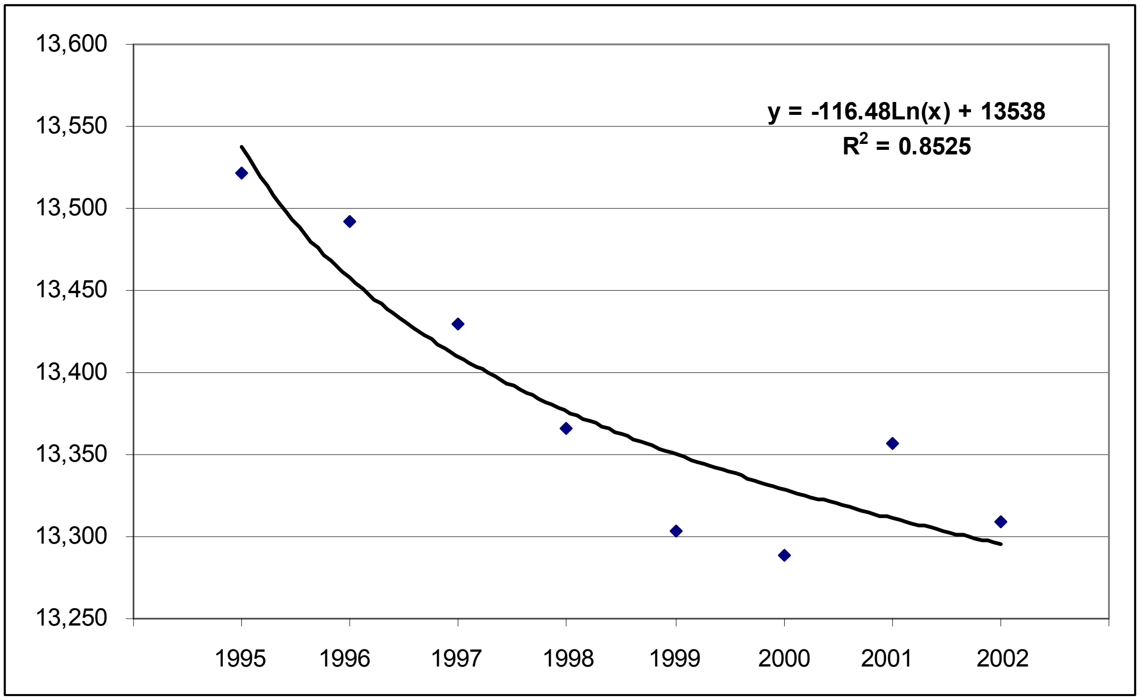
Table 2.4: Variable Correlation to Number of Residential Customers

	RCUS	HSTART	HHSIZE	HHOLD	POP	NMANEM	SVCEM	MANEM	TREND	RGAS	DISOIL	DINCAP	DISINC	OUTPUT	HSTOCK
RCUS	1	0.247	0.648	-0.611	-0.587	-0.592	-0.696	0.453	-0.488	0.432	0.426	-0.524	-0.556	-0.465	-0.923
HSTART	0.247	1	0.395	-0.458	-0.482	-0.204	-0.406	0.617	-0.373	0.346	0.168	-0.151	-0.273	0.243	0.392
HHSIZE	0.648	0.395	1	-0.985	-0.967	-0.940	-0.981	0.852	-0.969	0.846	0.834	-0.886	-0.933	-0.470	-0.945
HHOLD	-0.611	-0.458	-0.985	1	0.997	0.952	0.990	-0.875	0.970	-0.796	-0.777	0.914	0.962	0.511	0.993
POP	-0.587	-0.482	-0.967	0.997	1	0.947	0.983	-0.876	0.960	-0.764	-0.743	0.918	0.965	0.525	0.975
NMANEM	-0.592	-0.204	-0.940	0.952	0.947	1	0.964	-0.732	0.936	-0.754	-0.780	0.969	0.980	0.670	0.963
SVCEM	-0.696	-0.406	-0.981	0.990	0.983	0.964	1	-0.827	0.947	-0.786	-0.759	0.920	0.961	0.567	0.986
MANEM	0.453	0.617	0.852	-0.875	-0.876	-0.732	-0.827	1	-0.854	0.710	0.714	-0.688	-0.769	-0.205	-0.561
TREND	-0.488	-0.373	-0.969	0.970	0.960	0.936	0.947	-0.854	1	-0.865	-0.839	0.885	0.929	0.417	0.990
RGAS	0.432	0.346	0.846	-0.796	-0.764	-0.754	-0.786	0.710	-0.865	1	0.844	-0.663	-0.712	-0.176	-0.232
DISOIL	0.426	0.168	0.834	-0.777	-0.743	-0.780	-0.759	0.714	-0.839	0.844	1	-0.669	-0.708	-0.214	-0.348
DINCAP	-0.524	-0.151	-0.886	0.914	0.918	0.969	0.920	-0.688	0.885	-0.663	-0.669	1	0.990	0.763	0.931
DISINC	-0.556	-0.273	-0.933	0.962	0.965	0.980	0.961	-0.769	0.929	-0.712	-0.708	0.990	1	0.692	0.948
OUTPUT	-0.465	0.243	-0.470	0.511	0.525	0.670	0.567	-0.205	0.417	-0.176	-0.214	0.763	0.692	1	0.884
HSTOCK	-0.923	0.392	-0.945	0.993	0.975	0.963	0.986	-0.561	0.990	-0.232	-0.348	0.931	0.948	0.884	1
SERVICE	0.824	0.457	0.765	-0.706	-0.672	-0.623	-0.745	0.632	-0.671	0.706	0.699	-0.475	-0.555	-0.088	-0.570

In general, as the correlation between the dependent variable (residential customers) and the independent variables approaches one or negative one, the more highly correlated the independent variable is with the dependent variable. As can be seen in Table 2.4, none of the independent variables had a strong positive correlation with the dependent variable. Using a traditional regression analysis approach, CEA was not able to identify any independent variables from the data set listed above that provided a reasonable explanation of the entire historical data series, from 1983 through 2002. This is due in large part to the historical pattern of residential customer count data. The history demonstrates an average annual growth trend of 0.6% that occurred from 1983 through 1990 followed by a sharp decline in customer counts of 1.25% on an average annual basis from 1990 through 1995. The most recent history, from 1995 through 2002, demonstrated a more stable rate of attrition, approximately 0.23% on an annual average basis. Given that the data set has demonstrated three distinct patterns (0.6% growth, 1.25% decline and 0.23% decline) at three periods in time, as opposed to an underlying long term trend, and understanding that the intent of this forecast is to predict the number of residential customers for a five year period from 2003-2007, it seemed reasonable to truncate the historical data set to include only the more recent history from 1995 through 2002.

Using the truncated data series, CEA again attempted to identify independent variables that would offer reasonable explanatory capability in a regression equation for the number of residential customers. The analysis of the truncated data series did not produce more intuitive regression equations than were produced using the complete data set. Therefore, CEA opted to employ a curve estimation approach to fit the data and develop a reasonable residential customer count forecast. Using the truncated data set, CEA used a lognormal curve equation to develop the residential customer forecast. Table 2.5 below provides the truncated historical data set, the lognormal curve and the corresponding equation.

Table 2.5: Forecasting Equation for Number of Residential Customers



b) Residential Volume Regression

Similar to residential customers, residential demand experienced an increase over the initial period of the historical data set and then declined over the latter part of the period. Specifically, residential consumption grew from 1,227,057 Dth in 1983 to 1,285,742 Dth in 1989, a growth rate of 0.8% per year. In contrast, from 1989 to 2002, residential demand decreased from 1,285,742 Dth to 1,128,240 Dth or 1.0% per year, on average. Over the entire historical period, residential volumes declined approximately 0.4% per year.

Residential use (RVOL) was expected to be primarily driven by changes in the real price of gas, disposable income levels, housing stock and household size. As the price of gas rises, deliveries would be expected to fall, indicating a negative relationship. Also, as people have increasing disposable income and larger homes, sales would be expected to rise, indicating a positive relationship. Finally, as household size increases, one would expect the volume of gas consumed to increase. Table 2.6 contains a correlation matrix listing those variables considered significant in explaining residential consumption, their correlation to

RVOL and their correlation to each other. (All variables are listed by code name as described in the Data Description section.)

Table 2.6: Variable Correlations to Residential Sales Volumes

	RVOL	HSTART	HHSIZE	HHOLD	POP	NMANEM	SVCEM	MANEM	TREND	RGAS	DISOIL	DINCAP	DISINC	OUTPUT	HSTOCK
RVOL	1	0.538	0.710	-0.740	-0.746	-0.613	-0.739	0.796	-0.626	0.385	0.411	-0.614	-0.673	-0.388	-0.807
HSTART	0.538	1	0.395	-0.458	-0.482	-0.204	-0.406	0.617	-0.373	0.346	0.168	-0.151	-0.273	0.243	0.392
HHSIZE	0.710	0.395	1	-0.985	-0.967	-0.940	-0.981	0.852	-0.969	0.846	0.834	-0.886	-0.933	-0.470	-0.945
HHOLD	-0.740	-0.458	-0.985	1	0.997	0.952	0.990	-0.875	0.970	-0.796	-0.777	0.914	0.962	0.511	0.993
POP	-0.746	-0.482	-0.967	0.997	1	0.947	0.983	-0.876	0.960	-0.764	-0.743	0.918	0.965	0.525	0.975
NMANEM	-0.613	-0.204	-0.940	0.952	0.947	1	0.964	-0.732	0.936	-0.754	-0.780	0.969	0.980	0.670	0.963
SVCEM	-0.739	-0.406	-0.981	0.990	0.983	0.964	1	-0.827	0.947	-0.786	-0.759	0.920	0.961	0.567	0.986
MANEM	0.796	0.617	0.852	-0.875	-0.876	-0.732	-0.827	1	-0.854	0.710	0.714	-0.688	-0.769	-0.205	-0.561
TREND	-0.626	-0.373	-0.969	0.970	0.960	0.936	0.947	-0.854	1	-0.865	-0.839	0.885	0.929	0.417	0.990
RGAS	0.385	0.346	0.846	-0.796	-0.764	-0.754	-0.786	0.710	-0.865	1	0.844	-0.663	-0.712	-0.176	-0.232
DISOIL	0.411	0.168	0.834	-0.777	-0.743	-0.780	-0.759	0.714	-0.839	0.844	1	-0.669	-0.708	-0.214	-0.348
DINCAP	-0.614	-0.151	-0.886	0.914	0.918	0.969	0.920	-0.688	0.885	-0.663	-0.669	1	0.990	0.763	0.931
DISINC	-0.673	-0.273	-0.933	0.962	0.965	0.980	0.961	-0.769	0.929	-0.712	-0.708	0.990	1	0.692	0.948
OUTPUT	-0.388	0.243	-0.470	0.511	0.525	0.670	0.567	-0.205	0.417	-0.176	-0.214	0.763	0.692	1	0.884
HSTOCK	-0.807	0.392	-0.945	0.993	0.975	0.963	0.986	-0.561	0.990	-0.232	-0.348	0.931	0.948	0.884	1
SERVICE	0.614	0.457	0.765	-0.706	-0.672	-0.623	-0.745	0.632	-0.671	0.706	0.699	-0.475	-0.555	-0.088	-0.570

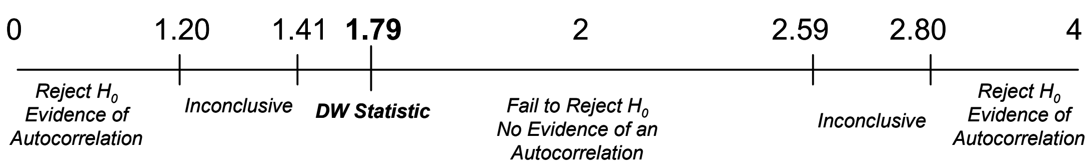
Referring to Table 2.6, while housing stock, and disposable income were expected to provide reasonable theoretical explanations of changes in the use of gas by residential customers, the negative relationship between these independent variables and the dependent variable are counterintuitive, therefore, neither of these variables was used in the final equation. The change in household size over time is positively correlated with residential customer volume and provides a reasonable explanation for increases in residential customer consumption. Therefore household size was used in the final regression equation. Table 2.7 lists the final equation for residential customer demand and summary regression statistics. The complete regression output is presented in the Appendix.

Table 2.7: Forecast Equation for Residential Sales

<table>
<tr><td colspan="6">log(RVOL) = C + log(HHSIZE) + AR</td></tr>
<tr><td colspan="6">Parameter Estimates and t-Statistics</td></tr>
<tr><td></td><td>C</td><td>HHSIZE</td><td colspan="3">AR</td></tr>
<tr><td>Coefficient</td><td>13.006452</td><td>1.0101348</td><td colspan="3">0.46386655</td></tr>
<tr><td>T-Statistic</td><td>34.57677</td><td>2.670826</td><td colspan="3">2.158889</td></tr>
<tr><td>Probability</td><td>0</td><td>0.01612667</td><td colspan="3">0.045444</td></tr>
<tr><td colspan="6">Summary Regression Statistics</td></tr>
<tr><td>R2</td><td colspan="2">F-Statistic</td><td>F-Stat Prob</td><td>DW-Statistic</td><td>DW Critical Value</td></tr>
<tr><td>0.625</td><td colspan="2">7.1333</td><td>0.0016126</td><td>1.7859877</td><td>1.41</td></tr>
</table>

The regression statistics as summarized by Table 2.7 indicate that household size is significant. The Durbin-Watson test on the initial regression equation indicated that we could not reject the hypothesis that serial correlation existed in the residuals. Therefore, CEA corrected for the presence of serial correlation by using the Prais-Winsten approach. As a result, the final equation includes an autoregressive term. Thus, after correcting for serial correlation, the final equation has an R-squared of .625, an acceptable DW, as illustrated in Table 2.7a, and the t-statistic for the independent variable is significant. Finally the F-statistic is also significant.

Table 2.7a: Durbin Watson Test for Autocorrelation[8]



c) Residential Forecast Results

The final equations were tested by performing a backcast to estimate residential customers and sales during the five year historical period. Table 2.8 compares the ex post forecast of residential customers and sales to actual customers and sales over the five year backcast period.

[8] Pursuant to the DTE's First Set of Information Requests, CEA has incorporated the table requested in DTE-1-17(d) and DTE-1-17(e).

Table 2.8: Residential Ex Post Forecast Analysis

	Residential Customers			Residential Sales - Dth		
	Actual	Ex Post	Variance	Actual	Ex Post	Variance
1998	13,366	13,376	0.1%	1,226,715	1,186,888	-3.2%
1999	13,303	13,350	0.4%	1,183,993	1,184,422	0.0%
2000	13,289	13,329	0.3%	1,173,251	1,190,679	1.5%
2001	13,357	13,311	-0.3%	1,131,008	1,182,506	4.6%
2002	13,309	13,296	-0.1%	1,128,240	1,180,489	4.6%
Mean Absolute Deviation			0.2%			2.8%
Mean Deviation			0.1%			1.5%

As one would expect using a curve estimation approach, the backcast results for the residential customer equation are reasonably close to the actual historical number of residential customers. As is indicated in Table 2.8, the results of the backcast for the residential sales volume produces a mean absolute deviation of 2.8% over the five year period, and a mean deviation of 1.5% for the five year period.

The forecasts generated from the equations described above are summarized in Table 2.9. As indicated in that table, the forecast equations project residential customer segment demand to remain relatively constant from 1,150,331 Dth in 2003 to 1,147,240 Dth in 2007. Residential customers are also projected to remain flat from 13,282 in 2003 to 13,239 in 2007.

Table 2.9: Residential Forecast Summary Results

Total Residential Customer Segment Forecast		
	Total Customers Forecast	*Total Sales Forecast Dth*
2003	13,282	1,150,331
2004	13,270	1,153,870
2005	13,258	1,151,836
2006	13,248	1,150,469
2007	13,239	1,147,240
'03-'07 CAGR	-0.08%	-0.07%

As a final check of the forecast, CEA compared the forecasted growth rate for residential customers and residential sales volumes to the growth rates of two prior periods. All data were weather normalized to facilitate comparison. The results of this analysis are presented in Table 2.10. As illustrated in the table, the forecasted -0.08% decline over the forecast period is consistent with the decline experienced from the periods of 1998-2002 and slower than 1994-1998, which were -0.11% and -0.77% respectively. On a total class sales basis, CEA projects that total residential customer sales will continue to decline, albeit modestly over the forecast period at a rate of 0.07%, as compared to the 2.07% decline in the 1998-2002 period and 0.12% annual increase in the 1994 to 1998 period.

Table 2.10: Residential Forecast Historical Comparison

	Historical Period (1994-1998)	*Historical Period (1998-2002)*	*Forecast Period (2003-2007)*
	Residential Forecast Comparison		
Customer Growth	-0.77%	-0.11%	-0.08%
Total Sales	0.12%	-2.07%	-0.07%

4. Small Commercial and Industrial Customer Segment (G-41 & G-51)

The Small C&I customer segment includes the G-41 and G-51 customer classes, which represent relatively small commercial business with a low load factor (G-41) or a high load factor (G-51). Similar to residential customers, the forecast for this customer segment includes separate forecasts for the number of customers and for total sales. The Small C&I customer segment includes primarily service sector businesses with annual average usage of 2,000 therms per customer or less. As can be seen in Table 2.11 below, Small C&I customers and sales have been increasing at an annual rate of 1.8% and 2.0% respectively.

Table 2.11: Historical Small C&I Customer Data

	Small C&I Customers	Small C&I Volume (Dth)
1983	828	163,709
1984	837	163,946
1985	849	180,960
1986	893	177,566
1987	954	171,723
1988	992	182,061
1989	1,024	190,036
1990	1,052	194,274
1991	1,065	197,537
1992	1,067	209,047
1993	1,068	205,994
1994	1,060	213,922
1995	1,054	230,717
1996	1,065	235,598
1997	1,081	240,931
1998	1,065	245,585
1999	1,131	233,519
2000	1,145	256,689
2001	1,179	264,313
2002	1,165	237,593
'83-'02 CAGR	1.8%	2.0%

a) Small Commercial and Industrial Customer Regression

The correlation matrix in Table 2.12 highlights the relationship between the number of Small C&I customers and several macroeconomic and regional demographic indicators. All variables listed are identified by code name as described in the Data Description section.

Table 2.12: Variable Correlation to Number of Small C&I Customers

	SCICUS	HSTART	HHSIZE	HHOLD	POP	NMANEM	SVCEM	MANEM	TREND	DISOIL	DINCAP	DISINC	OUTPUT	CGAS
SCICUS	1	-0.509	-0.925	0.964	0.972	0.902	0.926	-0.898	0.959	-0.752	0.874	0.926	0.414	-0.736
HSTART	-0.509	1	0.395	-0.458	-0.482	-0.204	-0.406	0.617	-0.373	0.168	-0.151	-0.273	0.243	0.356
HHSIZE	-0.925	0.395	1	-0.985	-0.967	-0.940	-0.981	0.852	-0.969	0.834	-0.886	-0.933	-0.470	0.829
HHOLD	0.964	-0.458	-0.985	1	0.997	0.952	0.990	-0.875	0.970	-0.777	0.914	0.962	0.511	-0.771
POP	0.972	-0.482	-0.967	0.997	1	0.947	0.983	-0.876	0.960	-0.743	0.918	0.965	0.525	-0.735
NMANEM	0.902	-0.204	-0.940	0.952	0.947	1	0.964	-0.732	0.936	-0.780	0.969	0.980	0.670	-0.723
SVCEM	0.926	-0.406	-0.981	0.990	0.983	0.964	1	-0.827	0.947	-0.759	0.920	0.961	0.567	-0.765
MANEM	-0.898	0.617	0.852	-0.875	-0.876	-0.732	-0.827	1	-0.854	0.714	-0.688	-0.769	-0.205	0.687
TREND	0.959	-0.373	-0.969	0.970	0.960	0.936	0.947	-0.854	1	-0.839	0.885	0.929	0.417	-0.834
DISOIL	-0.752	0.168	0.834	-0.777	-0.743	-0.780	-0.759	0.714	-0.839	1	-0.669	-0.708	-0.214	0.836
DINCAP	0.874	-0.151	-0.886	0.914	0.918	0.969	0.920	-0.688	0.885	-0.669	1	0.990	0.763	-0.624
DISINC	0.926	-0.273	-0.933	0.962	0.965	0.980	0.961	-0.769	0.929	-0.708	0.990	1	0.692	-0.676
OUTPUT	0.414	0.243	-0.470	0.511	0.525	0.670	0.567	-0.205	0.417	-0.214	0.763	0.692	1	-0.140
CGAS	-0.736	0.356	0.829	-0.771	-0.735	-0.723	-0.765	0.687	-0.834	0.836	-0.624	-0.676	-0.140	1

As can be seen in Table 2.12, service sector employment, non-manufacturing employment, population, disposable income per capita, disposable income, and households are highly correlated with the number of small commercial customers and with each other.

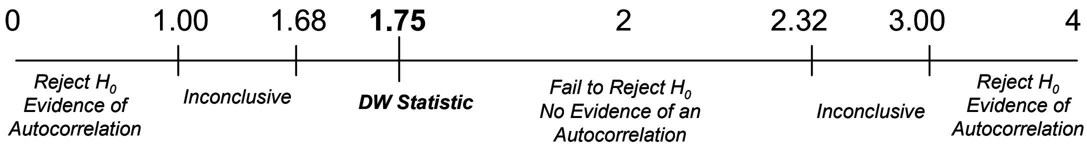
When combined, service sector employment, population, and a trend variable provide the best overall regression statistics and therefore are used in the final equation. One would expect that as population increases, the number of small commercial and industrial customers in the region would also increase. This positive relationship is illustrated in the correlation matrix in Table 2.12 above. Similarly one would expect a positive relationship between services employment and small commercial customers, as is seen in the correlation matrix. As illustrated in Table 2.13, however, the coefficient of services employment is negative in the final regression equation. While this seems counterintuitive and could cause one to eliminate the variable from the equation, it is more likely that the population variable is tempering the strength of the service employment variable. Since both variables are significant and removing either of the variables compromised the explanatory capability of the equation, CEA chose to accept the equation. The complete regression output is presented in the Appendix.

Table 2.13: Forecast Equation for Number of Small C&I Customers

log(SCICUS) = C + log(POP) + log(SVCEM)+ log(TREND)				
	C	POP	SVCEM	TREND
Coefficient	-33.062	3.428	-0.551	0.049
T-Statistic	-6.231	7.335	-5.126	3.106
Probability	0	0	0	0.007
Summary Regression Statistics				
Adjusted R2	F-Statistic	F-Stat Prob	DW-Statistic	DW Critical Value
0.979	9.645	0.007	1.75	1.68

The regression statistics summarized by Table 2.13 above indicate that this equation explains a significant amount of the trend in Small C&I customers. Specifically, all the independent variables are significant, the model has a significant F-statistic, and the adjusted R-squared is .979. Referring to Table 2.13a, the Durbin-Watson result of 1.75 is above the Durbin-Watson critical value for the number of observations used in the regression analysis. Exceeding the critical value allows us to reject the presence of an autocorrelation in the residuals.

Table 2.13a: Durbin Watson Test for Autocorrelation[9]



b) Small Commercial and Industrial Volume Regression

Similar to Small C&I customers, Small C&I sales volumes grew over the 1983-2002 time period from 163,709 Dth to 237,593 Dth or 2.0% per year. While growth is the general trend over the study period, periods of declining demand have occurred. For example, from 1985 through 1987, small commercial customer demand declined from 180,960 Dth to 171,723 Dth.

The correlation matrix in Table 2.14 highlights the relationship between Small C&I demand and several macroeconomic and regional demographic indicators. Small C&I sales were expected to be driven by changes in the real price of gas and by service sector employment. A negative relationship was expected between the price of gas and Small C&I demand, while a positive relationship was expected between Small C&I volumes and service employment.

Table 2.14: Variable Correlation to Small C&I Sales Volumes

	SCIVOL	HSTART	HHSIZE	HHOLD	POP	NMANEM	SVCEM	MANEM	TREND	DISOIL	DINCAP	DISINC	OUTPUT	RESOIL	CGAS
SCIVOL	1	-0.473	-0.956	0.952	0.940	0.888	0.962	-0.826	0.911	-0.717	0.819	0.878	0.418	-0.330	-0.750
HSTART	-0.473	1	0.395	-0.458	-0.482	-0.204	-0.406	0.617	-0.373	0.168	-0.151	-0.273	0.243	0.107	0.356
HHSIZE	-0.956	0.395	1	-0.985	-0.967	-0.940	-0.981	0.852	-0.969	0.834	-0.886	-0.933	-0.470	0.472	0.829
HHOLD	0.952	-0.458	-0.985	1	0.997	0.952	0.990	-0.875	0.970	-0.777	0.914	0.962	0.511	-0.425	-0.771
POP	0.940	-0.482	-0.967	0.997	1	0.947	0.983	-0.876	0.960	-0.743	0.918	0.965	0.525	-0.399	-0.735
NMANEM	0.888	-0.204	-0.940	0.952	0.947	1	0.964	-0.732	0.936	-0.780	0.969	0.980	0.670	-0.400	-0.723
SVCEM	0.962	-0.406	-0.981	0.990	0.983	0.964	1	-0.827	0.947	-0.759	0.920	0.961	0.567	-0.349	-0.765
MANEM	-0.826	0.617	0.852	-0.875	-0.876	-0.732	-0.827	1	-0.854	0.714	-0.688	-0.769	-0.205	0.484	0.687
TREND	0.911	-0.373	-0.969	0.970	0.960	0.936	0.947	-0.854	1	-0.839	0.885	0.929	0.417	-0.557	-0.834
DISOIL	-0.717	0.168	0.834	-0.777	-0.743	-0.780	-0.759	0.714	-0.839	1	-0.669	-0.708	-0.214	0.779	0.836
DINCAP	0.819	-0.151	-0.886	0.914	0.918	0.969	0.920	-0.688	0.885	-0.669	1	0.990	0.763	-0.320	-0.624
DISINC	0.878	-0.273	-0.933	0.962	0.965	0.980	0.961	-0.769	0.929	-0.708	0.990	1	0.692	-0.354	-0.676
OUTPUT	0.418	0.243	-0.470	0.511	0.525	0.670	0.567	-0.205	0.417	-0.214	0.763	0.692	1	0.196	-0.140
RESOIL	-0.330	0.107	0.472	-0.425	-0.399	-0.400	-0.349	0.484	-0.557	0.779	-0.320	-0.354	0.196	1	0.614
CGAS	-0.750	0.356	0.829	-0.771	-0.735	-0.723	-0.765	0.687	-0.834	0.836	-0.624	-0.676	-0.140	0.614	1

As is indicated in Table 2.14, the number of households, population, services employment, disposable income and disposable income per capita were found to be

[9] Pursuant to the DTE's First Set of Information Requests, CEA has incorporated the table requested in DTE-1-22(c) and DTE-1-22(d).

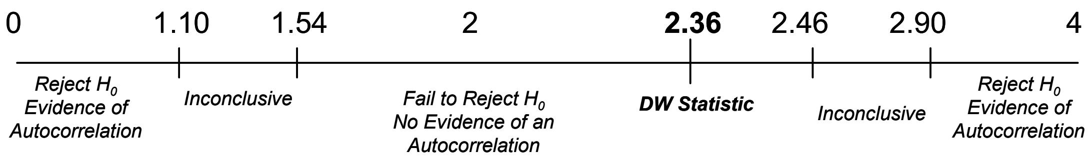
significant in explaining changes in Small C&I sales. In addition, there is an intuitive relationship between these independent variables and Small C&I sales. The positive relationship in the correlation matrix indicates that as these independent variables increase, Small C&I sales also increase. Not surprisingly, given the correlations shown in Table 2.14, population, service employment, disposable income and disposable income per capita are not only correlated to Small C&I volumes, but are also correlated to each other. Disposable income per capita and services employment were chosen from this group of similar variables because the combination of these variables produced the best regression statistics. Gas prices were somewhat correlated with Small C&I sales and the negative relationship illustrated in the correlation matrix is also intuitive. As gas prices decline, we would expect to see an increase in gas consumption. However, when used in the regression equations, gas prices did not provide significant explanatory capability. Table 2.15 lists the final equation for Small C&I sales and its regression statistics. The complete regression output is presented in the Appendix.

Table 2.15: Forecast Equation for Small Commercial and Industrial Sales

<table>
<tr><td colspan="5">log(SCIVOL) = C + log(DINCPC) + log(SVCEMP)</td></tr>
<tr><td colspan="5">Parameter Estimates and t-Statistics</td></tr>
<tr><td></td><td>C</td><td>DINCPC</td><td colspan="2">SVCEMP</td></tr>
<tr><td>Coefficient</td><td>1.717</td><td>-0.743</td><td colspan="2">1.128</td></tr>
<tr><td>T-Statistic</td><td>2.652</td><td>-3.318</td><td colspan="2">10.411</td></tr>
<tr><td>Probability</td><td>0.017</td><td>0.004</td><td colspan="2">0</td></tr>
<tr><td colspan="5">Summary Regression Statistics</td></tr>
<tr><td>Adjusted R2</td><td>F-Statistic</td><td>F-Stat Prob</td><td>DW-Statistic</td><td>DW Critical Value</td></tr>
<tr><td>0.95</td><td>181.777</td><td>0</td><td>2.362</td><td>2.46</td></tr>
</table>

The resulting equation produces a reasonable explanation for changes in Small C&I customer volumes. Disposable income per capita and services employment, two measures of economic growth can be expected to reasonably predict the level of demand for natural gas from Small C&I customers. The regression statistics summarized in Table 2.15 above indicate that the equation explains a significant amount of the trend in Small C&I sales. The independent variables are significant, the equation has a significant F-statistic, the adjusted R-squared is 0.95, and the Durbin-Watson result falls between 1.54 and 2.46 on the line in Table 2.15a, thereby indicating no evidence of autocorrelation.

Table 2.15a: Durbin Watson Test for Autocorrelation



In reviewing this equation, one might question the validity of using disposable income per capita as an explanatory variable, given the negative coefficient that is produced in the final regression equation. The sign of the variables in the regression equation however is not the appropriate indicator of the relationship between the independent and dependent variables. The positive or negative relationship between any independent variable and the dependent variable is appropriately measured through the correlation tables, where the effect of each independent variable on the dependent variable can be isolated. Once combined in a regression equation, sign changes are common, particularly between variables that are highly correlated. Therefore, since the correlation between disposable income per capita and Small C&I sales is positive, a result we would expect, CEA included the variable in the equation.

c) Small Commercial and Industrial Forecast Results

To test the robustness of the forecasting equations, FG&E tested the performance of the Small C&I segment equations discussed above by using the equations to backcast the past five years of historical demand and customers. Table 2.16 compares the ex post forecast of Small C&I customers and sales to actual customers and class sales from 1998 through 2002.

Table 2.16: Small C&I Ex Post Forecast Analysis

	Small Commercial and Industrial Customers			Small Commercial and Industrial Sales - Dth		
	Actual	Ex Post	Variance	Actual	Ex Post	Variance
1998	1,065	1,099	3.2%	245,585	240,729	-2.0%
1999	1,131	1,129	-0.2%	233,519	243,649	4.3%
2000	1,145	1,148	0.3%	256,689	245,047	-4.5%
2001	1,179	1,186	0.7%	264,313	254,150	-3.8%
2002	1,165	1,197	2.7%	237,593	250,259	5.3%
Mean Absolute Deviation			1.4%			4.0%
Mean Deviation			1.3%			-0.1%

The results of the backcast indicate the Small C&I customer equation was able to predict the actual number of Small C&I customers within a 3.2% tolerance each year, while the Small C&I volume equation predicted historical demand within a 5.3% tolerance each year. In fact, the mean absolute deviations for the customer and volume equations were 1.4% and 4.0% respectively over the backcast period and on a mean deviation basis, the customer and volume equations produced variances of 1.3% and -0.1% respectively.

Table 2.17 illustrates the projected Small C&I customers and associated demand for the 2003 to 2007 forecast period, utilizing the equations described above.

Table 2.17: Small C&I Forecast Summary Results

Total Small Commercial and Industrial Customer Segment Forecast		
	Total Customers Forecast	*Total Sales Forecast Dth*
2003	1,188	254,608
2004	1,181	262,207
2005	1,179	267,169
2006	1,177	269,595
2007	1,171	273,538
'03-'07 CAGR	-0.36%	1.81%

As is indicated in the table, CEA projects that the Small C&I customer segment demand will grow from 254,608 Dth in 2003 to 273,538 Dth in 2007. The total number of customers, however is projected to decline slightly from 1,188 to 1,171 over the forecast period. This represents a -0.36% and 1.81% annual growth rate in customers and volumes respectively.

Similar to the residential forecast, FG&E compared the Small C&I segment forecast growth rates to the growth rates of the two prior historic periods. Again, all data were weather normalized. The results of this analysis are presented in Table 2.18. As is illustrated in the table, a decrease in the number of customers is forecasted at -0.36% as compared to increases of 2.28% and 0.11% experienced in the 1998-2002 and 1994-1998 periods respectively. On a total class sales basis, CEA projects growth in demand of 1.81% per year as compared to a decline of 0.82% for the 1998-2002 period and an increase of 3.51% for the 1994-1998 period.

Table 2.18: Small C&I Forecast Historical Comparison

	Historical Period (1994-1998)	*Historical Period (1998-2002)*	*Forecast Period (2003-2007)*
	Small Commercial and Industrial Forecast Comparison		
Customer Growth	0.11%	2.28%	-0.36%
Total Sales	3.51%	-0.82%	1.81%

5. Medium Commercial and Industrial Customer Segment (G-42 and G-52)

The Medium C&I customer segment aggregates the customers and demand from the G-42 and G-52 customer classes, which represent medium low load factor customers (G-42) and medium high load factor customers (G-52). These customers have an average annual consumption of 18,000 to 20,000 therms. As can be seen in Table 2.19 below, FG&E experienced growth in the number of Medium C&I customers from 1983 through 1991, from 223 to 266 customers followed by several years of generally flat customer counts in 1991-1998, when customer counts ranged from 262 to 266 customers. The data set indicates a sharp drop in the number of customers from 1998 to 1999, flowed by a general growth trend through 2002 to 270 customers. FG&E believes that the volatility in the customer counts over the most recent three years of history is the result of customer reclassification that occurred when customers were assigned to new customer rate classes.

The Medium C&I sales data shows a stronger growth pattern from 1983 through 1998, with sales increasing from 383,941 Dth to 549,509 Dth. From 1998 through 2002, sales volumes for Medium C&I customers declined from 549,509 Dth to 490,590 Dth.

Table 2.19: Historical Medium C&I Customer Data

	Medium C&I Customers	Medium C&I Volume (Dth)
1983	223	383,941
1984	224	390,690
1985	226	420,416
1986	234	407,546
1987	245	390,714
1988	251	408,530
1989	258	427,740
1990	263	429,191
1991	266	440,071
1992	265	461,817
1993	264	468,238
1994	262	482,046
1995	259	507,249
1996	262	519,537
1997	266	533,530
1998	264	549,509
1999	248	517,202
2000	250	493,864
2001	255	478,317
2002	270	490,590
'83-'02 CAGR	1.0%	1.3%

As shown in Table 2.19, the compound annual growth rate for Medium C&I customers from 1983 through 2002 was 1.0%, while, Medium C&I customer demand grew at a compound annual growth rate of 1.3%.

a) Medium Commercial and Industrial Customer Regression

Based on prior experience, CEA expected that the number of Medium C&I customers (MCICUS) should be driven by employment levels, specifically in the manufacturing sector and disposable income or disposable income per capita. Table 2.20 contains a correlation matrix of those variables thought to be significant in explaining the number of Medium C&I customers.

Table 2.20: Variable Correlation to Number of Medium C&I Customers

	MCICUS	POP	NMANEM	SVCEM	MANEM	TREND	DISOIL	DINCAP	DISINC	OUTPUT	CGAS	RESOIL
MCICUS	1	0.771	0.689	0.701	-0.801	0.839	-0.736	0.629	0.692	0.106	-0.764	-0.689
POP	0.771	1	0.947	0.983	-0.876	0.960	-0.743	0.918	0.965	0.525	-0.735	-0.399
NMANEM	0.689	0.947	1	0.964	-0.732	0.936	-0.780	0.969	0.980	0.670	-0.723	-0.400
SVCEM	0.701	0.983	0.964	1	-0.827	0.947	-0.759	0.920	0.961	0.567	-0.765	-0.349
MANEM	-0.801	-0.876	-0.732	-0.827	1	-0.854	0.714	-0.688	-0.769	-0.205	0.687	0.484
TREND	0.839	0.960	0.936	0.947	-0.854	1	-0.839	0.885	0.929	0.417	-0.834	-0.557
DISOIL	-0.736	-0.743	-0.780	-0.759	0.714	-0.839	1	-0.669	-0.708	-0.214	0.836	0.779
DINCAP	0.629	0.918	0.969	0.920	-0.688	0.885	-0.669	1	0.990	0.763	-0.624	-0.320
DISINC	0.692	0.965	0.980	0.961	-0.769	0.929	-0.708	0.990	1	0.692	-0.676	-0.354
OUTPUT	0.106	0.525	0.670	0.567	-0.205	0.417	-0.214	0.763	0.692	1	-0.140	0.196
CGAS	-0.764	-0.735	-0.723	-0.765	0.687	-0.834	0.836	-0.624	-0.676	-0.140	1	0.614
RESOIL	-0.689	-0.4	-0.4	-0.349	0.484	-0.557	0.779	-0.32	-0.354	0.196	0.614	1

As shown in Table 2.20, manufacturing employment had the strongest correlation but was negatively correlated with MCICUS. While this relationship initially seems counterintuitive, declining manufacturing employment provides an indication of the shifting makeup of the economy. As is illustrated by the strong negative correlation between manufacturing employment and services employment, the regional economy is shifting from a more heavily manufacturing oriented economy to a service sector economy. This point is also illustrated by the positive correlation between service employment and medium C&I customers and between non-manufacturing employment and medium C&I customers. As the region continues this trend, similar to trends in the overall US economy, FG&E expects that manufacturing employment levels will maintain the negative relationship with Medium C&I customers, and therefore accepted the variable for use in the final equation.

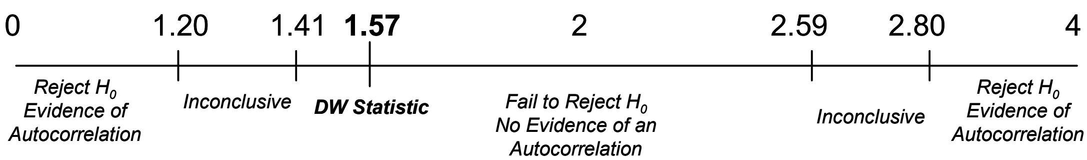
Table 2.21 shows the final equation for the number of Medium C&I customers and associated regression statistics. The complete regression output is presented in the Appendix.

Table 2.21: Forecasting Equation for Number of Medium C&I Customers

log(MCICUS) = C + log(MANEM) + AR				
Parameter Estimates and t-Statistics				
	C	MANEM	AR	
Coefficient	10.418804	-0.439291	0.640608	
T-Statistic	6.03561156	-2.8343687	3.43978	
Probability	0.000	0.011	0.00156	
Summary Regression Statistics				
R2	F-Statistic	F-Stat Prob	DW-Statistic	DW Critical Value
0.748	8.033643081	0.011445765	1.566453	1.41

The regression statistics as summarized by Table 2.21 indicate that the independent variable, manufacturing employment, is significant. The Durbin-Watson test on the initial regression equation indicated that we could not reject the hypothesis that there was no serial correlation in the residuals. Therefore, CEA corrected for the presence of serial correlation by using the Prais-Winsten approach. As a result, the final equation includes an autoregressive term. As is illustrated in Table 2.21a below, after correcting for serial correlation, the DW statistic is within the range where there is no evidence of autocorrelation. In addition, the equation produced has R-squared of .748 and the t-statistic for the independent variable is significant. Finally the F-statistic is also significant.

Table 2.21a: Durbin Watson Test for Autocorrelation[10]



b) Medium Commercial and Industrial Volume Regression

As discussed earlier, Medium C&I sales volumes increased from 383,941 Dth in 1983 to 490,590 Dth in 2002 or an average annual growth rate of 1.3%. Medium C&I sales (MCIVOL) were expected to be driven by changes in the real price of gas and by measures of the economy such as disposable income per capita. A negative relationship was expected between the price of gas and sales, while a positive relationship was expected between disposable income per capita and sales. Table 2.22 provides the variables considered relevant in explaining the Medium C&I customer segment sales and their correlations to MCIVOL, as well as the correlations between the independent variables.

[10] Pursuant to the DTE's First Set of Information Requests, CEA has incorporated the table requested in DTE-1-26(d) and DTE-1-26(e).

Table 2.22: Variable Correlation to Medium C&I Sales Volumes

	MCIVOL	POP	NMANEM	SVCEM	TREND	MANEM	DISOIL	DINCAP	DISINC	OUTPUT	CGAS
MCIVOL	1	0.831	0.782	0.872	0.860	-0.764	-0.815	0.662	0.735	0.204	-0.877
POP	0.831	1	0.947	0.983	0.960	-0.876	-0.743	0.918	0.965	0.525	-0.735
NMANEM	0.782	0.947	1	0.964	0.936	-0.732	-0.780	0.969	0.980	0.670	-0.723
SVCEM	0.872	0.983	0.964	1	0.947	-0.827	-0.759	0.920	0.961	0.567	-0.765
TREND	0.860	0.960	0.936	0.947	1	-0.854	-0.839	0.885	0.929	0.417	-0.834
MANEM	-0.764	-0.876	-0.732	-0.827	-0.854	1	0.714	-0.688	-0.769	-0.205	0.687
DISOIL	-0.815	-0.743	-0.780	-0.759	-0.839	0.714	1	-0.669	-0.708	-0.214	0.836
DINCAP	0.662	0.918	0.969	0.920	0.885	-0.688	-0.669	1	0.990	0.763	-0.624
DISINC	0.735	0.965	0.980	0.961	0.929	-0.769	-0.708	0.990	1	0.692	-0.676
OUTPUT	0.204	0.525	0.670	0.567	0.417	-0.205	-0.214	0.763	0.692	1	-0.140
CGAS	-0.877	-0.735	-0.723	-0.765	-0.834	0.687	0.836	-0.624	-0.676	-0.140	1

As shown in Table 2.22, population, services employment, and commercial gas prices, each have a strong correlation with MCIVOL. Disposable income and disposable income per capita are also somewhat correlated with MCIVOL. When modeled, the combination of disposable income, services employment and commercial gas prices produced the most acceptable regression statistics. Services employment and disposable income both provide a general measure of the growth in the economy, as these indicators increase we would expect the output from medium commercial and industrial customers to grow, thereby increasing the consumption of natural gas by this customer class. The negative relationship between gas prices and medium commercial and industrial customers is also reasonable. As gas prices increase, we would expect to see consumption decrease. The relationships expressed in the correlation matrix validate these assumptions.

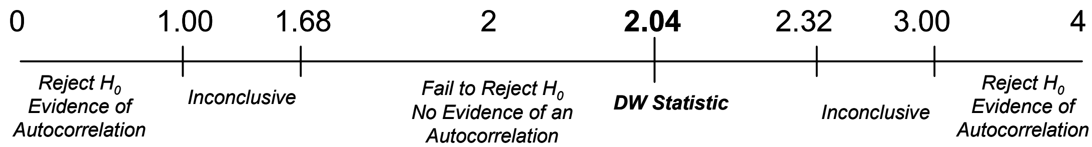
Table 2.23: Forecasting Equation for Medium C&I Sales

log(MCIVOL) = C + log(CGAS) + log(SVCEMP) + log(DISINC)				
Parameter Estimates and t-Statistics				
	C	CGAS	SVCEMP	DISINC
Coefficient	5.293	-0.226	0.985	-0.878
T-Statistic	3.5	-3.684	6.23	-4.658
Probability	0.003	0.002	0	0
Summary Regression Statistics				
Adjusted R2	F-Statistic	F-Stat Prob	DW-Statistic	DW Critical Value
0.933	89.239	0	2.044	2.32

Table 2.23 lists the final equation for Medium C&I segment sales and associated regression statistics. The complete regression output is presented in the Appendix. The

regression statistics indicate that all independent variables are significant. In addition, as is indicated in Table 2.23a, the results of the Durbin-Watson test allow us to reject the hypothesis that there is serial correlation in the residuals. Finally, the F-statistic is also significant.

Table 2.23a: Durbin Watson Test for Autocorrelation



c) Medium Commercial and Industrial Forecast Results

Similar to the Residential and Small C&I customer segments, FG&E tested the accuracy of the Medium C&I segment equations by using a backcasting approach. Table 2.24 compares the results of the backcast to the actual customers and demand over a historical five year period from 1998-2002.

Table 2.24: Medium C&I Ex Post Forecast Analysis

	Medium Commercial and Industrial Customers			Medium Commercial and Industrial Sales - Dth		
	Actual	Ex Post	Variance	Actual	Ex Post	Variance
1998	264	261	-1.2%	549,509	519,449	-5.5%
1999	248	262	5.4%	517,202	515,144	-0.4%
2000	250	259	3.4%	493,864	501,335	1.5%
2001	255	262	2.8%	478,317	483,000	1.0%
2002	270	267	-1.3%	490,590	503,153	2.6%
Mean Absolute Deviation			2.8%			2.2%
Mean Deviation			1.8%			-0.2%

As summarized in Table 2.24, an absolute value basis, the Medium C&I customer and volume variances averaged 2.8% and 2.2% respectively. The mean deviation for the customer equation was 1.8%, while the mean deviation for the volume equation was -0.2%.

The Medium C&I customer forecast results generated from the equations described above are summarized in Table 2.25 below. As illustrated in the table, FG&E projects Medium C&I sales to grow slowly and steadily from 515,633 Dth to 541,288 Dth from 2003 to 2007. However, CEA expects the total number of Medium C&I customers to decrease slightly over the forecast period from 269 to 264 customers from 2003 to 2007.

Table 2.25: Medium C&I Forecast Summary Results

Total Medium Commercial and Industrial Customer Segment Forecast		
	Total Customers Forecast	*Total Sales Forecast Dth*
2003	269	515,633
2004	268	526,730
2005	266	536,325
2006	265	537,778
2007	264	541,288
'03-'07 CAGR	-0.47%	1.22%

As indicated by Table 2.25 above, on an average annual basis, the forecasts project the number of medium commercial and industrial customers to decline by 0.47% while demand is expected to increase by 1.22%.

As with the previous customer segments, CEA compared the Medium C&I segment forecasted growth rates to growth rates of the two prior historic periods. Again, all data were weather normalized to facilitate comparison. The results of this analysis are presented in Table 2.26. Specifically, Medium C&I customers are forecasted to decline at a rate of 0.47% per year as compared to a 0.60% growth rate experienced in the 1998-2002 period and 0.20% annual growth rate in the 1994-1998 period. On a customer segment sales basis, CEA projects an annual growth rate of 1.22% as compared to -2.80% per year rate for the 1998-2002 period and a 3.33% annual growth for the 1994-1998 period.

Table 2.26: Medium C&I Forecast Historical Comparison

	Historical Period (1994-1998)	*Historical Period (1998-2002)*	*Forecast Period (2003-2007)*
	Medium Commercial and Industrial Forecast Comparison		
Customer Growth	0.20%	0.60%	-0.47%
Total Sales	3.33%	-2.80%	1.22%

6. Large Commercial and Industrial Customer Segment (G-43 and G-53)

The Large C&I customer segment forecasts aggregate customers and sales in the G-43 and G-53 customer classes, which represents large low load factor customers (G-43) and large high load factor customers (G-53). The G-43 and G-53 classes include FG&E's largest customers, with an annual consumption per customer that exceeds 20,000 Dth. As can be seen in Table 2.27 below, FG&E has experienced continuous, albeit slow growth in the number of industrial customers over the study period, increasing from 17 in 1983 to 23 in 2002. While the general trend in Large C&I demand has increased over the study period, there are slight upturns and downturns in the consumption pattern on a year to year basis. For example from 1983 through 1985, demand increased from 274,809 Dth to 315,802 Dth. This growth trend is followed, however, by a decline in volumes from 1985 levels to 268,011 Dth in 1988. From 1991 to 2001, there is a pattern of sustained growth in Large C&I demand from 308,763 Dth to 478,276 Dth.

Table 2.27: Historical Large C&I Customer Data

	Large C&I Customers	Large C&I Volume (Dth)
1983	17	274,809
1984	17	290,594
1985	17	315,802
1986	18	280,288
1987	18	256,783
1988	18	268,011
1989	18	287,984
1990	19	280,454
1991	19	308,763
1992	19	331,166
1993	19	364,394
1994	18	371,905
1995	18	376,066
1996	19	394,769
1997	19	435,800
1998	19	440,750
1999	17	447,221
2000	20	467,575
2001	25	478,276
2002	23	443,991
'83-'02 CAGR	1.5%	2.6%

As shown in Table 2.27, the compound annual growth rate for Large C&I customers from 1983 through 2002 was 1.5%, while Large C&I customer demand grew at a compound annual growth rate of 2.6%.

a) Large Commercial and Industrial Customer Regression

The number of Large C&I customers (LCICUS) was expected to be driven by manufacturing employment levels and disposable income or disposable income per capita. Table 2.28 contains a correlation matrix of the variables considered to be relevant in explaining the number of LCICUS customers. All variables listed are identified by code name as described in the Data Description section.

Table 2.28: Variable Correlation to Number of Large C&I Customers

	LCICUS	POP	NMANEM	SVCEM	MANEM	TREND	DINCAP	DISINC	OUTPUT	IGAS	RESOIL
LCICUS	1	0.738	0.659	0.701	-0.663	0.613	0.703	0.729	0.586	0.258	0.066
POP	0.738	1	0.947	0.983	-0.876	0.960	0.918	0.965	0.525	-0.278	-0.399
NMANEM	0.659	0.947	1	0.964	-0.732	0.936	0.969	0.980	0.670	-0.306	-0.400
SVCEM	0.701	0.983	0.964	1	-0.827	0.947	0.920	0.961	0.567	-0.297	-0.349
MANEM	-0.663	-0.876	-0.732	-0.827	1	-0.854	-0.688	-0.769	-0.205	0.298	0.484
TREND	0.613	0.960	0.936	0.947	-0.854	1	0.885	0.929	0.417	-0.471	-0.557
DINCAP	0.703	0.918	0.969	0.920	-0.688	0.885	1	0.990	0.763	-0.193	-0.320
DISINC	0.729	0.965	0.980	0.961	-0.769	0.929	0.990	1	0.692	-0.227	-0.354
OUTPUT	0.586	0.525	0.670	0.567	-0.205	0.417	0.763	0.692	1	0.210	0.196
IGAS	0.258	-0.278	-0.306	-0.297	0.298	-0.471	-0.193	-0.227	0.210	1	0.706
RESOIL	0.066	-0.399	-0.400	-0.349	0.484	-0.557	-0.320	-0.354	0.196	0.706	1

As shown in Table 2.28, industrial gas prices were positively correlated with LCICUS; because this relationship was counterintuitive, the price of natural gas to industrial customers was not used to develop the Large C&I customer equation. Disposable income, disposable income per capita, population and service sector employment, which are highly correlated with each other, were all significant indicators of LCICUS. Population, being a measure of overall growth in the region seemed to be a reasonable indicator of the number of large C&I customers. Growth in services employment in the region is likely to coincide with an increase in population, as people are drawn to increased employment opportunities. In addition, while the price of residual oil appears to have a low correlation with Large C&I customers, it is reasonable to assume that as the price of an alternate fuel rises, the number of large C&I customers switching to natural gas will likely increase. These two variables, when used together in the final regression equation, produced the most robust results.

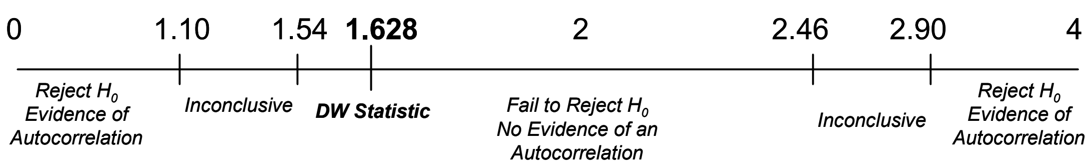
Table 2.29 shows the final equation for number of Large C&I customers and the associated summary regression statistics. The complete regression output is presented in the Appendix.

Table 2.29: Forecasting Equation for Number of Large C&I Customers

log(LCICUS) = C + log(POP)) + log(RESOIL)				
Parameter Estimates and t-Statistics				
	C	POP	RESOIL	
Coefficient	-21.380	1.764	0.138	
T-Statistic	-5.517	6.258	2.950	
Probability	0.000	0.000	0.009	
Summary Regression Statistics				
Adjusted R2	F-Statistic	F-Stat Prob	DW-Statistic	DW Critical Value
0.663	19.703	0	1.628	1.54

The regression statistics as summarized in Table 2.29 indicate that the independent variables are significant. As is indicated in table 2.29a, the DW value indicates that there is no serial correlation in the residuals and the t-statistics on both independent variables indicate that the variables are significant. Finally, the F-statistic is also significant.

Table 2.29a: Durbin Watson Test for Autocorrelation



b) Large Commercial and Industrial Volume Regression

CEA expected the Large C&I customer segment sales volumes (LCIVOL) to be driven by changes in the real price of gas for industrial customers and by employment levels. Thus, a negative relationship was expected between the price of gas for industrial customers and sales, while a positive relationship was expected between employment levels and sales. Table 2.30 provides those variables considered relevant in explaining Large C&I class sales volumes and their correlation to LCIVOL and to each other. All variables are listed by code name as described in the Data Description section.

Table 2.30: Variable Correlation to Large C&I Sales Volumes

	LCIVOL	POP	NMANEM	SVCEM	MANEM	TREND	DINCAP	DISINC	OUTPUT	IGAS	RESOIL
LCIVOL	1	0.852	0.790	0.901	-0.750	0.792	0.722	0.783	0.401	-0.154	-0.157
POP	0.852	1	0.947	0.983	-0.876	0.960	0.918	0.965	0.525	-0.278	-0.399
NMANEM	0.790	0.947	1	0.964	-0.732	0.936	0.969	0.980	0.670	-0.306	-0.400
SVCEM	0.901	0.983	0.964	1	-0.827	0.947	0.920	0.961	0.567	-0.297	-0.349
MANEM	-0.750	-0.876	-0.732	-0.827	1	-0.854	-0.688	-0.769	-0.205	0.298	0.484
TREND	0.792	0.960	0.936	0.947	-0.854	1	0.885	0.929	0.417	-0.471	-0.557
DINCAP	0.722	0.918	0.969	0.920	-0.688	0.885	1	0.990	0.763	-0.193	-0.320
DISINC	0.783	0.965	0.980	0.961	-0.769	0.929	0.990	1	0.692	-0.227	-0.354
OUTPUT	0.401	0.525	0.670	0.567	-0.205	0.417	0.763	0.692	1	0.210	0.196
IGAS	-0.154	-0.278	-0.306	-0.297	0.298	-0.471	-0.193	-0.227	0.210	1	0.706
RESOIL	-0.157	-0.399	-0.400	-0.349	0.484	-0.557	-0.320	-0.354	0.196	0.706	1

As is illustrated in the correlations provided in Table 2.30, the price of industrial gas on the FG&E system by itself was not significant in explaining changes in LCIVOL. Manufacturing employment is negatively correlated with LCIVOL. Again, while this seems counterintuitive, the negative relationship illustrates a shift in the regional economy over time from a manufacturing to services based economy. This seems reasonable given the positive relationship between services employment and large C&I volume. In addition, population, disposable income, and disposable income per capita are all significant variables that could provide reasonable explanatory capability for LCIVOL. The final equation included service sector employment and disposable income, both indicators of the growth in the economy.

The initial regression equation, which included the two variables discussed above, provided a reasonable adjusted R-squared, indicating that the variables explained much of the variation in the industrial volume data. The results of the Durbin-Watson test, however, did not allow for the rejection of serial correlation in the residuals. In order to correct for serial correlation, CEA used the Prais-Winsten autoregressive technique, and an autoregressive term was added to the equation. While the sign of disposable income is negative in the final equation, since the correlation between large C&I volume and disposable income is positive, disposable income was used in the equation. The sign change from the correlation table to the regression equation is likely due to the interaction between population and disposable income.

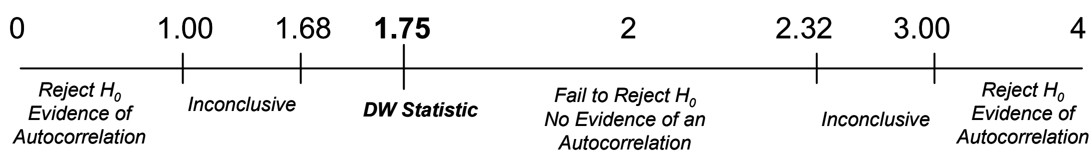
Table 2.31 lists the final equation for Large C&I class sales and the associated summary regression statistics. The complete regression output is presented in the Appendix.

Table 2.31: Forecasting Equation for Large C&I Sales

log(LCIVOL) = C + log(DISINC) + log(SVCEMP)+AR				
Parameter Estimates and t-Statistics				
	C	DISINC	SVCEMP	AR
Coefficient	-5.1801599	-1.279106	1.8880804	0.58630639
T-Statistic	-1.3469802	-2.167955	3.9987875	2.895
Probability	0.19675615	0.04558686	0.00103466	0.011
Summary Regression Statistics				
R2	F-Statistic	F-Stat Prob	DW-Statistic	DW Critical Value
0.930	21.32552	0.00003067	1.7531499	1.68

As indicated by the above table, the independent variables are significant. In addition, results of the Durbin-Watson test on the adjusted equation, which includes the autoregressive term, allow us to reject the hypothesis that serial correlation is present in the residuals. This is illustrated in Table 2.31a. Finally the F-statistic is also significant.

Table 2.31a: Durbin Watson Test for Autocorrelation



c) Large Commercial and Industrial Forecast Results

In order to determine the strength of the forecasting equations, CEA applied the same backcasting methodology to the Large C&I customer and demand equations as was used to test the regression equations of the Residential, Small and Medium C&I customer segments. Table 2.32 compares the results of the backcast to the actual customers and demand over a historical five year period from 1998-2002.

Table 2.32: Large C&I Ex Post Forecast Analysis

	Large Commercial and Industrial Customers			Large Commercial and Industrial Sales - Dth		
	Actual	Ex Post	Variance	Actual	Ex Post	Variance
1998	19	19	-1.5%	440,750	429,805	-2.5%
1999	17	20	13.0%	447,221	430,685	-3.7%
2000	20	21	6.6%	467,575	426,952	-8.7%
2001	25	22	-12.2%	478,276	446,604	-6.6%
2002	23	22	-4.2%	443,991	433,505	-2.4%
Mean Absolute Deviation			7.5%			4.8%
Mean Deviation			0.3%			-4.8%

As summarized in Table 2.32, on an absolute value basis the Large C&I customers and volume variances averaged 7.5% and 4.8% respectively. The mean deviation for the customer equation was 0.3% over the backcast period, while the mean deviation for the volume equation was -4.8% over the backcast period.

As is illustrated in Table 2.33 below, CEA projects Large C&I sales to grow steadily from 451,336 Dth to 495,355 Dth from 2003 to 2007; however, CEA expects the total number of large commercial and industrial customers, to remain essentially flat over that same time period.

Table 2.33: Large C&I Forecast Summary Results

Total Large Commercial and Industrial Customer Segment Forecast		
	Total Customers Forecast	*Total Sales Forecast Dth*
2003	22	451,336
2004	22	469,496
2005	22	480,769
2006	22	485,575
2007	22	495,355
'03-'07 CAGR	0.38%	2.35%

As indicated by Table 2.33 above, the projected average annual growth rate for Large C&I customers and associated demand is 0.38 % and 2.35% respectively.

Similar to the previous customer segments, FG&E compared the Large C&I segment forecasted growth rates to two prior periods. All data has been weather normalized to facilitate comparison, the results of this analysis are presented in Table 2.34 below.

Table 2.34: Large C&I Forecast Historical Comparison

	Historical Period (1994-1998)	*Historical Period (1998-2002)*	*Forecast Period (2003-2007)*
	Large Commercial and Industrial Forecast Comparison		
Customer Growth	1.01%	4.71%	0.38%
Total Sales	4.34%	0.18%	2.35%

As indicated in the table, customer growth is limited, with a compound annual growth rate of 0.38% over the forecast period. The projected compound annual growth rate for total Large C&I customer demand is 2.35%, compared with 0.18% compound annual growth for the 1998-2002 time period, and 4.34% for the 1994-1998 period.

7. Total Company Forecast

As discussed above, CEA utilized a backcasting approach to evaluate the regression equations that were developed for each customer segment. However, given the size of certain customer segments, coupled with the data transformation issues related to the transition to the new rate structure, CEA has also backcast the total number of customers and sales for the entire company. As can be seen in Table 2.35 below, when the backcast results across the past five years of historical data are aggregated for all customer segments, the equations produced results within 0.4% for customers and 3.5% for volumes each year. On an absolute value basis the customers and volume variances over the backcast period averaged 0.3% and 1.7% respectively and the mean deviation for the customers was 0.2% and for volumes was -0.3% over the backcast period.

Table 2.35: Total Company Ex Post Forecast Analysis

	Total Customers			Total Sales - Dth		
	Actual	Ex Post	Variance	Actual	Ex Post	Variance
1998	14,714	14,755	0.3%	2,462,560	2,376,870	-3.5%
1999	14,700	14,761	0.4%	2,381,936	2,373,900	-0.3%
2000	14,704	14,757	0.4%	2,391,379	2,364,014	-1.1%
2001	14,815	14,781	-0.2%	2,351,915	2,366,260	0.6%
2002	14,768	14,782	0.1%	2,300,414	2,367,407	2.9%
Mean Absolute Deviation			0.3%			1.7%
Mean Deviation			0.2%			-0.3%

Next, the forecast results, generated from each of the individual customer segment forecasts discussed above, were aggregated into a total company sales forecast. As is illustrated in Table 2.36 below, CEA projects total company sales to grow steadily from 2,371,907 Dth to 2,457,421 Dth from 2003 to 2007. CEA expects the total number of firm customers to decline slightly from 14,833 to 14,736 over that same time period.

Table 2.36: Total Company Forecast Summary Results

Total Company Forecast		
	Total Customers Forecast	*Total Sales Forecast Dth*
2003	14,833	2,371,907
2004	14,813	2,412,302
2005	14,807	2,436,099
2006	14,785	2,443,416
2007	14,736	2,457,421
'03-'07 CAGR	-0.16%	0.89%

As indicated by Table 2.36 above, the projected annual growth rate for total customers and volumes is -0.16% and 0.89 % respectively.

Similar to the customer segment forecasts, CEA compared the total customer and volume forecasts to the growth rates of the two prior historic periods. All data is weather normalized to facilitate comparison. The results of this analysis are presented in Table 2.37 below.

Table 2.37: Total Company Forecast Historical Comparison

	Historical Period (1994-1998)	*Historical Period (1998-2002)*	*Forecast Period (2003-2007)*
	Total Company Forecast Comparison		
Customer Growth	-0.69%	0.09%	-0.16%
Total Sales	1.84%	-1.69%	0.89%

As indicated in the above table, the total number of customers is projected to decline slightly and the associated sales volume is predicted to grow at a relatively slow rate of 0.89%.

E. *NORMAL YEAR THROUGHPUT FORECAST*

In Section D above, CEA developed a volume forecast that represents total end use consumption of firm customers, including sales and transportation customers. To develop the total company requirements this end use forecast needs to reflect billing cycle effects, lost and unaccounted for gas and company use as well as anticipated firm transport volumes. CEA developed the total company throughput forecast by analyzing the historical relationship between end use consumption and total company throughput requirements. The resultant analysis was utilized to forecast total company throughput requirements for the 2003-2007 period, as shown by Table 2.38 below. More detail on the analysis can be found in the Appendix.

Table 2.38: Total Company Normal Year Firm Throughput

	Firm Sales Forecast	Firm Throughput Forecast
2003	2,371,907	2,413,545
2004	2,412,302	2,450,251
2005	2,436,099	2,470,177
2006	2,443,416	2,473,520
2007	2,457,421	2,483,765

The difference between total company throughput requirements and end use consumption ranges from 1.76% to 1.07% on an annual basis, which is reasonable given the recent FG&E experience.

F. *FIRM TRANSPORT*

In the approval order for FG&E's last Gas IRP in D.T.E. 00-42 the Department directed the Company to develop a firm transportation forecast in its next filing based on actual experience and the associated collection of relevant data and information to appropriately develop the forecast. As described earlier, CEA developed customer segment regression equations for total volumes including both sales and transportation. Since there is insufficient data to estimate regression equations to explain customer switching behavior by customer segment, CEA utilized a scenario methodology to forecast transportation volumes. As discussed in more detail below, CEA identified three scenarios, based upon the collection and analysis of historical firm transportation experiences for FG&E, which provide a range of transportation migration by customer segment. These ranges were then applied to the throughput volumes forecasted to calculate transportation volumes by customer segment.

In June of 1999, FG&E began offering firm transportation ("FT") service to its customers. This FT offering was in conjunction with the gas unbundling collaborative and certain DTE orders and therefore is consistent with other Massachusetts LDCs. The experience to date regarding FT, however, has been varied. The initial response to the FT offering was significant with respect to Large C&I customer activity. Almost 55% of the Large C&I customers and 70% of the Large C&I volumes migrated to transportation. However over the past twelve months a reverse migration as begun with customers returning to sales service. Figures 4 and 5 summarize the migration trend for FG&E's Large C&I customers.

Figure 4: Large C&I Firm Sales Customers vs. Firm Transportation Customers

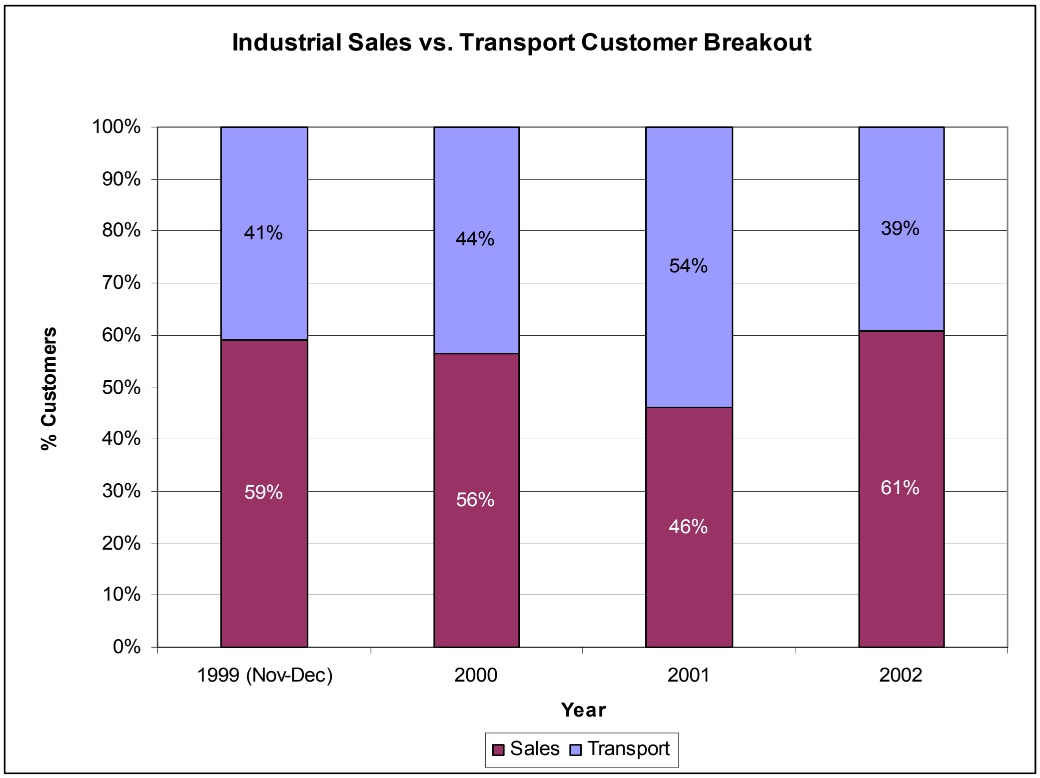
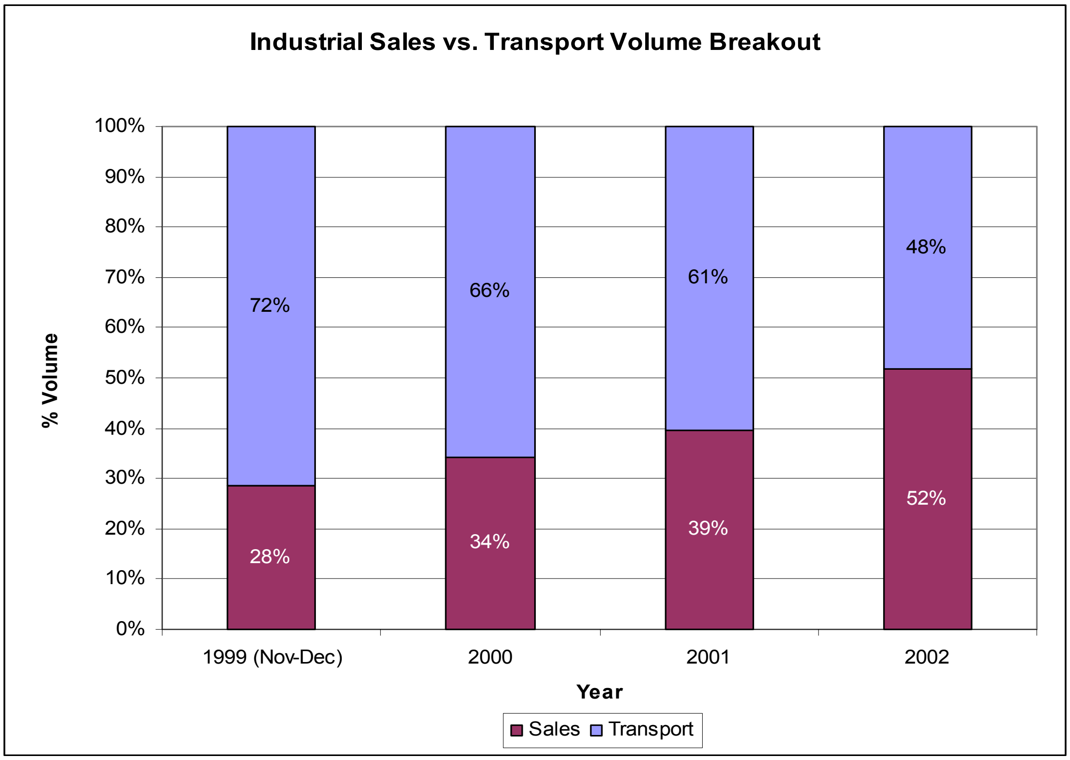


Figure 5: Large C&I Firm Sales Volumes vs. Firm Transportation Volumes



As illustrated by Figures 5, the migration to FT service peaked in the 1999 and 2000 timeframe, when approximately 70% of the total Large C&I volumes were transportation volume. By 2002, Large C&I FT volumes had declined to less than 50% of total Large C&I sales. Many factors, including the reduction of market participants (both wholesale and retail), continued price volatility, and counterparty credit concerns have influenced this trend and as such FG&E has attempted to develop three scenarios that cover a range of likely FT migration outcomes. As noted below, the FT scenarios have been developed in terms of the same four customer segment levels used to generate the total demand forecast.

To develop the scenarios of FT migration over the forecast period, CEA reviewed the migration history by customer segment. The forecast scenarios were developed based on CEA's expectation of reasonable levels of migration, given the history experienced since the inception of the program in 1999. (See the Appendix for the actual transportation data by customer segment.) The following three scenarios include a base case or planning scenario and two alternative cases including a high and low scenario.

Table 2.39: Firm Transportation Volumes by Customer Segment

Firm Transport Volumes as a Percent of Total Deliveries by Class

	Low FT	Base FT	High FT
Residential	0%	0%	0%
Small C&I	0%	0.2%	0.5%
Medium C&I	0%	14%	15%
Large C&I	0%	25%	65%

FT-Base Case Scenario

The Base Case Scenario for FT reflects FG&E's current migration experience. Due to the variation and cyclicality in the actual transportation data, in order to develop this scenario, CEA utilized migration data from December 2002, by customer segment. CEA applied the average transportation migration percentages, by customer segment, (Residential, Small C&I, Medium C&I and Large C&I) to each segment demand forecast to determine the transportation demand by customer segment. It is important to note that, since FG&E experienced no residential customer migration to FT service since the implementation of the transportation program, all residential customers were assumed to remain as sales customers.

As illustrated in Table 2.39, FG&E experienced very limited migration from the Small C&I customer segment; 0.2% in December 2002. Therefore, to develop the base scenario, the Small C&I component of the FT forecast was assumed to be 0.2% of the total Small C&I throughput forecast in each forecast year.

Similarly, FG&E evaluated the FT migration within the Medium C&I customer segment in December 2002. As shown in Table 2.39, during that time period, FG&E experienced a Medium C&I customer migration rate of 14%. Therefore, the Medium C&I component of the FT forecast was assumed to be 14% of the total Medium C&I throughput forecast in each forecast year.

Utilizing the methodology described above, CEA calculated the migration of Large C&I customers in December 2002 to be 25%. Therefore, the FT base scenario reflects 25% of the total throughput forecast for the Large C&I customer segment. Once the base FT scenarios were calculated for each of the four customer segments, they were aggregated to develop the total Base FT Scenario.

FT-Low Scenario

As discussed above, when FG&E initially implemented its transportation program in 1999, the Company experienced rapid migration of Large C&I customers and associated loads from FG&E supply to third party suppliers. In 2000, however, migration rates slowed significantly and from 2001 to the present, FG&E has experienced some reverse migration, with Medium and Large C&I customers returning to the FG&E sales services. FG&E believes that it is reasonable to expect this trend to continue given the lack of growth in activity by competitive suppliers. Recently, FG&E was notified by one of the largest third party suppliers that has been active on its system that it would no longer be supplying retail customers in the Company's service territory. This supplier's peak capacity requirement to serve its load during the past three years was 2,000 Dth. Its current capacity is 200 Dth, none of which will be renewed once the current customer contracts expire. Although this is only one, albeit significant supplier, FG&E determined that for planning purposes, it was important to consider an FT scenario wherein all current transportation customers return to sales service and in effect there are no transportation volumes. The Low FT Scenario captures this possibility.

FT-High Scenario

To establish the High FT Scenario, CEA again reviewed the historical data available from the transportation program. Using this data, CEA calculated the High FT Scenario based on the higher of either (i) the average transportation participation from 1999 through 2002, or (ii) the average participation over the last twelve months. In essence, CEA utilized the highest migration percentage experienced over any 12-month period.

In order to develop the forecast of demand for the High FT Scenario, CEA utilized a methodology similar to that which was employed in the Base FT Scenario. The participation rates listed above in Table 2.39 were developed for each of the four customer segments and applied to the total throughput forecast for the respective customer segments. The High FT scenario then was calculated as the sum of the individual customer segment High FT transport scenarios.

As noted previously, FG&E has not experienced residential customer migration thus far in the program. Accordingly CEA has not included migration of any residential volumes in the FT scenarios. As indicated in Table 2.39, in the high scenario, CEA assumed that 0.5%

of Small C&I customer sales would migrate to FT service in each year of the forecast period. Similarly, CEA assumed 15% and 65% of Medium C&I and Large C&I total sales, respectively, would migrate to transportation under the High FT Scenario. In order to develop the total transportation forecast for the different FT Scenarios, the migration percentages described above were applied to the total throughput forecast developed for each customer class segment. The customer class level FT forecasts then were aggregated to develop the total transportation forecast for the FT scenarios. The results of this process are summarized in Table 2.40.

Table 2.40: Firm Sendout Forecast by FT Scenario

	Firm Throughput Forecast	Low FT	Base FT	High FT	Low FT	Base FT	High FT
		Normal Firm Sendout			Normal Firm Transport		
2003	2,413,545	2,413,545	2,224,756	2,035,029	-	188,789	378,516
2004	2,450,251	2,450,251	2,255,596	2,058,694	-	194,655	391,557
2005	2,470,177	2,470,177	2,271,626	2,070,377	-	198,551	399,800
2006	2,473,520	2,473,520	2,273,868	2,070,983	-	199,652	402,537
2007	2,483,765	2,483,765	2,281,453	2,074,887	-	202,312	408,878

As noted in Table 2.40 there are no transportation volumes in the Low FT case, while the High FT Case assumes that approximately 16% of total volumes are transportation volumes. In the Planning or Base FT Case, approximately 8% of total volumes are transportation volumes.

G. *PLANNING STANDARDS AND DESIGN FORECASTS*

The Company utilized certain planning standards to design its gas supply portfolio. These standards include: weather data, normal year degree days, design year degree days and design day degree days.

1. Weather Data

Development of the planning standards begins with the identification of a complete and updated weather database. As reported earlier in the Data Description section, the Company uses the Worcester-Bedford database, which continues to be updated with official data collected at the two weather stations. The database has been approved in the Company's previous three Gas Integrated Resource Plans, see Orders in DPU 94-140, DTE 98-55, and

DTE 00-42. In its probability analysis of the design weather conditions, CEA utilized data from 11/01/1968 through 10/31/2002, encompassing a period of 35 complete gas years.

The calculations of HDD for various design year and design day weather conditions were developed using a model initially prepared by Management Applications Consulting, Inc., which is now maintained by the Company. This model was approved in the Company's last three Integrated Resources Plans. The model calculates the mean and standard deviations of the data then applies a normal distribution to derive HDD levels associated with different probabilities of occurrence. Yearly and peak day HDD levels with probabilities of occurring once in 20, 30, 40, 50 and 100 years were calculated. The output illustrating these calculations is presented in the Appendix.

2. Normal Year Degree-Day Standard

While FG&E plans its gas supply to meet design standards, it recognizes that a normal year is more likely to occur. CEA determined its normal gas year standard to be 6,655 HDD by calculating an arithmetic average of HDD for each of the past 35 gas years (1968/69 – 2001/02) from the Worcester-Bedford database.

3. Design Year Degree-Day Standard

The Company currently uses a 1 in 30 year occurrence for its design cold year standard. Table 2.41 shows the HDD expected in a normal gas year, and in design gas years with probabilities of occurring once in 30, 50 and 100 years. As mentioned above, the normal year standard is the arithmetic average of 6,655 HDD observed over the past 35 gas years. The standard deviation around this average was 343.9 HDD. Applying a standard normal distribution, the HDD associated with design cold gas years with probabilities of 1 in 30, 1 in 50 and 1 in 100 were calculated.

In addition to developing the weather distribution, CEA also calculated the associated demand. To calculate demand, CEA analyzed the actual daily throughput as a function of actual daily weather for the period 1983 to 2002. The data was sorted by month and separate regressions were developed for each month, which allowed for the calculation of a daily baseload and weather sensitive component for each month. The individual base load and weather-sensitive components were applied to the normal HDD for each month, and were aggregated to obtain an annual estimate of throughput based on the monthly regression results.

In order to account for system load growth, the equations were adjusted as follows. The throughput estimate generated using the monthly regression equations was compared to the normal year throughput forecast generated from the customer class level regression equations discussed above. The difference between these two estimates of normal year throughput was identified as system load growth and was allocated to each month based on the ratio of monthly to annual weather-sensitive throughput. This allocation adjusted the weather-sensitive components of the monthly regressions for the growth that was not captured by the monthly regression equations.

Using the new monthly weather sensitive components CEA was able to disaggregate the normal year throughput projection generated using the customer class level equations into the normal annual baseload and weather sensitive throughput. The annual weather sensitive throughput was divided by the annual normal HDD to obtain an annual weather sensitive component. Finally, the annual HDD associated with each design year probability was multiplied by the annual weather sensitive component and added to the annual baseload component to generate the forecast for each design year scenario. These forecasts are shown in Table 2.41.

Table 2.41: Design Year Heating Degree-Day Scenarios and Demand Forecast

Heating Degree-Days by Design Cold Year					
	Mean	**Std. Dev.**	**1 in 30**	**1 in 50**	**1 in 100**
Normal Year HDD	6,655	343.9			
Design Year HDD			7,283	7,359	7,452
Incremental HDD			628	703	797
Firm Sendout (year 2003) by Design Cold Year					
		Normal	**1 in 30**	**1 in 50**	**1 in 100**
Low FT Scenario		2,413,545	2,560,603	2,578,537	2,600,213
Base FT Scenario		2,224,756	2,360,311	2,376,842	2,396,823
High FT Scenario		2,035,029	2,159,023	2,174,145	2,192,422
Transportation (year 2003) by Design Cold Year					
Low FT Scenario		-	-	-	-
Base FT Scenario		188,789	200,292	201,694	203,390
High FT Scenario		378,516	401,580	404,392	407,792

Table 2.42 shows the design cold year forecast over the forecast period, presented in terms of firm sendout and firm transport under the Low, Base, and High FT Scenarios. The forecast reflects design cold year conditions expected to occur once every thirty years.

Table 2.42: Design Cold (1 in 30) Year Firm Sendout

	Design Firm Throughput	Low FT	Base FT	High FT	Low FT	Base FT	High FT
		Design Firm Sendout			Design Firm Transport		
2003	2,560,603	2,560,603	2,360,311	2,159,023	-	200,292	401,580
2004	2,600,770	2,600,770	2,394,157	2,185,160	-	206,613	415,610
2005	2,622,575	2,622,575	2,411,774	2,198,109	-	210,801	424,466
2006	2,626,233	2,626,233	2,414,255	2,198,844	-	211,978	427,389
2007	2,637,445	2,637,445	2,422,615	2,203,267	-	214,830	434,177

4. Design Day Degree-Day Standard

The Company currently uses a 1 in 30 year occurrence for its design day standard. Table 2.44 shows the HDD expected during a normal peak day, and during peak days with probabilities of occurring once in 30, 50 and 100 years. The normal year peak day is 62 HDD, rounded from the arithmetic average of 62.49 HDD observed over the past 35 gas years. The standard deviation around this average was 4.8. Applying a standard normal distribution, the HDD associated with design cold days with probabilities of occurring once in 30 years, once in 50 years and once in 100 years were calculated to be 71, 72 and 73, respectively. These calculations are presented in detail in the Appendix.

On the FG&E system, base load and weather-sensitive components for peak days were estimated, using data for the peak day experienced each winter from 1983 through 2002. The data were modeled by regressing peak day firm throughput against HDD that day and a trend variable. To assess how well the estimated parameters fit the actual peak days experienced, they were used to backcast peak day throughput for the past 5 years, given the actual HDD that occurred. The results of this analysis are presented in Table 2.43 below. The detailed regression output is provided in the Appendix.

Table 2.43: Design Peak Day Ex Post Analysis

	Peak Day		
	Actual	Ex Post	Variance
1998	16,007	15,691	-2.01%
1999	18,317	17,754	-3.17%
2000	20,956	19,538	-7.26%
2001	16,939	17,132	1.13%
2002	16,542	16,403	-0.85%
Mean Absolute Deviation			2.88%
Mean Deviation			-2.43%

Applying the peak day base load and weather-sensitive components to the HDD associated with each design condition, peak day forecasts were generated for each design condition. These forecasts are shown in Table 2.44.

Table 2.44: Design Cold Day Heating Degree-Days and Peak Day Gas Loads

Heating Degree-Days by Design Cold Day					
	Mean	**Std. Dev.**	**1 in 30**	**1 in 50**	**1 in 100**
Normal Day HDD	62	4.8			
Design Day HDD			71	72	73
Incremental HDD			9	10	11
Firm Sendout (Day 2003) by Design Cold Day					
		Normal	**1 in 30**	**1 in 50**	**1 in 100**
Low FT Scenario		19,575	22,025	22,318	22,683
Base FT Scenario		18,043	20,302	20,573	20,908
High FT Scenario		16,505	18,571	18,818	19,125
Transportation (Day 2003) by Design Cold Day					
Low FT Scenario		-	-	-	-
Base FT Scenario		1,531	1,723	1,746	1,774
High FT Scenario		3,070	3,454	3,500	3,557

Table 2.45 shows the design cold day forecast over the forecast period, presented in terms of firm sendout and firm transport under the Low FT, Base FT, and High FT Scenarios. The forecast reflects design cold day conditions expected to occur once every thirty years.

Table 2.45: Design Day (1 in 30) Firm Sendout and Transport

	Design Firm Throughput	Low FT	Base FT	High FT	Low FT	Base FT	High FT
		Design Firm Sendout			Design Firm Transport		
2003	22,025	22,025	20,302	18,571	-	1,723	3,454
2004	22,133	22,133	20,374	18,596	-	1,758	3,537
2005	22,241	22,241	20,453	18,641	-	1,788	3,600
2006	22,349	22,349	20,545	18,712	-	1,804	3,637
2007	22,457	22,457	20,627	18,760	-	1,829	3,697

III. RESOURCE ASSESSMENT

A. *RESOURCE PLANNING GUIDELINES*

FG&E's resource planning, acquisition and management process is guided by the Company's Gas Resource Planning Guidelines (the Guidelines). The Guidelines are flexible criteria which serve to focus the decision making process on the key factors leading to success in achieving a reliable least-cost system. The Guidelines are not precise quantitative standards because such standards can never reflect the myriad of factors that must be assessed given the complexity and uncertainty of the long range planning process for an LDC. Over reliance on quantitative analyses or inflexible numerical standards, no matter how sophisticated, can never entirely replace sound professional judgment based on solid evaluation using contemporary analytical techniques and the experience of the marketplace. FG&E recognizes that competitive market forces, properly utilized within the framework of the Guidelines, may be harnessed to provide firm customers with significant value. The strength of the Company's resource portfolio can be demonstrated by making an assessment of the Plan's compliance with the Guidelines. This section reviews each of the Guidelines and provides a discussion of how the Company's Plan conforms to these Guidelines.

The Company’s Resource Planning Guidelines are listed below. Each Guideline is elaborated upon further following the list.

1. Maintain a reliable, flexible planning process that results in meeting firm customers needs at the least cost.

2. Employ resource identification and acquisition procedures that result in procurement of appropriate demand and supply side resources.

3. Maintain a portfolio of long and short-term resources capable of meeting firm customer needs effectively, even in changing and uncertain market conditions.

4. Acquire achievable cost-effective demand-side resources through orderly implementation of DSM programs.

5. Maintain diversity of natural gas supplies through:
    - Geological and geographical diversity of supply basins;
    - Limiting dependence on individual suppliers; and
    - Limiting reliance on Canadian and other imported resources.

6. Maintain costs within a competitive range.

7. Manage the risks of non-price factors associated with gas supply and transportation contracts.

8. Maintain local production capability to supplement pipeline supplies on peak winter days and to meet firm customers needs during the summer for a pipeline failure.

9. Seek to identify cost-effective alternative pipeline deliveries to reduce risk of failure of the interstate pipeline facilities serving the Company.

1. Maintain a reliable, flexible planning process which results in meeting firm customer needs at the least cost. This Guideline is demonstrated by the continual planning and review of market opportunities conducted by FG&E staff and management during the preparation of monthly supply plans throughout the heating season and less frequently during the non-heating season. FG&E implements its cost optimization plans by conducting RFPs to meet identified resource requirements at the best market prices available and through the use of optimization tools, such as SENDOUT®, when appropriate. FG&E's current RFP process is detailed further in this document. RFP's are routinely issued on an annual and seasonal basis to procure additional peaking and pipeline supplies. The RFP process was recently utilized in arriving at a determination to enter into an agreement with Tennessee Gas Pipeline ('TGP") for a Zone 6-to-6 firm short haul transportation contract of 550 Dth/day for a thirteen month term beginning on December 1, 2002 as approved by the Department on January 3, 2003 in D.T.E. 02-55. The RFP process was also used to procure one year contracts starting November 1, 2003 with Amerada Hess, ConocoPhillips and Distrigas of Massachusetts LLC (DOMAC); winter 2003/2004 contracts with Emera Energy, Duke Energy Field Service and NJR Resources and a four year contract with DOMAC that was filed with the DTE for review and approval on October 1, 2003.

The RFP process includes evaluation of available resources in three phases as follows: 1) drafting and issuance of an RFP and receipt of supplier bids, 2) selection of a short list of suppliers from the bids submitted, and 3) negotiation with listed suppliers and selection of winning proposals.

The Company utilizes RFP's in order to meet its identified resource needs given current market conditions and portfolio status. Needs are assessed with current information and forecasts of future market conditions in relation to the specific needs of the portfolio and expected levels of firm customer demand. Portfolio optimization is performed via the use of the SENDOUT® Optimization Software, market information, and Company judgment based upon numerous years of market experience.

Typically, RFP's are sent to a list of potential suppliers, then a short list of suppliers are subsequently selected for their ability to provide reliable service at the most competitive prices and/or flexible terms and conditions. After bids are received, the Company continues to conduct informal discussions with each short-listed supplier in order to clarify and improve bids. The negotiations follow an iterative process whereby an ongoing effort is made to move the contract price, terms and conditions into a package that maximizes the service and other non-price performance factors while minimizing price and risk.

After the short list is created, the Company develops analyses to compare the price and non-price attributes of competing bids. In most cases, pricing and flexibility options are evaluated using the SENDOUT® Optimization Software to identify the proposal that offers the optimal least cost solution given existing resources and expected demand levels. Examples of price and non-price attributes that may be considered (in the event that these attributes are applicable to specific needs at specific time periods) are as follows: 1) index formulas used to develop commodity prices; 2) reservation or demand charges; 3) price caps; 4) nominating flexibility; 5) financial viability of suppliers; 6) supply warranty provisions, 7) supply diversity; 8) the extension of credit from suppliers to FG&E; and 9) all other attributes that allow the company to operate within the procurement Guidelines presented here.

2. Employ resource identification and acquisition procedures which result in procurement of appropriate demand and supply side resources. This guideline is demonstrated by the Company's ongoing planning and market-based procurement activities whereby required resources are identified and the RFP process is implemented, each as described above.

3. Maintain a portfolio of resources capable of meeting firm customer needs effectively, even in changing and uncertain market conditions. The implementation of this Guideline provides a guard against the Company experiencing excessive resource demands or excessive resource supplies at a single point in time, while affording the flexibility to acquire or discontinue supply resources in regular, consistent blocks. Compliance with this Guideline requires a mix of short to medium term contract lengths with staggered or seasonal termination dates. This Guideline was most recently utilized by the Company in the TGP capacity contract restructuring plan approved by the Department on April 24, 2003 in D.T.E. 02-85.

The FG&E supply portfolio conforms with this Guideline with its local production facilities and its mix of transportation and underground storage contracts that expire over the 5-year planning period while providing broad flexibility to the Company in the form of term extension options. Due to the uncertain state of gas unbundling and the rapidly changing state of financial pressures on gas suppliers and marketers, maintaining flexibility of supply resources is a key consideration in the Company's portfolio optimization process. The Company therefore maintains a portfolio of transportation contracts that have variable deliverability and termination dates through 2008 as a result of the capacity contract restructuring plan recently approved by the Department in D.T.E. 02-85 while maintaining commodity contracts of shorter-term duration.

FG&E's entire supply portfolio has commodity prices that are linked to published price indices that allow FG&E to lock in the price for any remaining term of the contract by notifying the supplier, confirming the price and committing to receive the volumes of locked-in gas in accordance with the terms and conditions of each contract. The risk of being unable to acquire the necessary volumes in the short to medium term markets is small given the level of FG&E's resource needs, the competitiveness of the gas market and the primary firm transportation contracts which FG&E holds with Tennessee Gas Pipeline Company. This strategy provides the Company with the flexibility needed to pursue new transportation and supply alternatives and to adapt to changing market conditions as they develop.

4. Acquire achievable cost-effective demand-side resources through orderly implementation of DSM programs. The Company is committed to the implementation of cost-effective DSM programs as a means to satisfy its total firm customer requirements at the least cost. The Company filed its most recent Energy Efficiency Program "Status Report and Proposed Program Update" which was approved on July 3rd, 2003, under docket D.T.E. 98-049. The cost-effectiveness of DSM programs is determined based on the cost of program implementation and existing/ projected average delivered gas prices. Once implemented, DSM resources are essentially base loaded into the resource mix. As such, DSM programs are implemented under a separate process than is utilized to make supply side resource decisions.

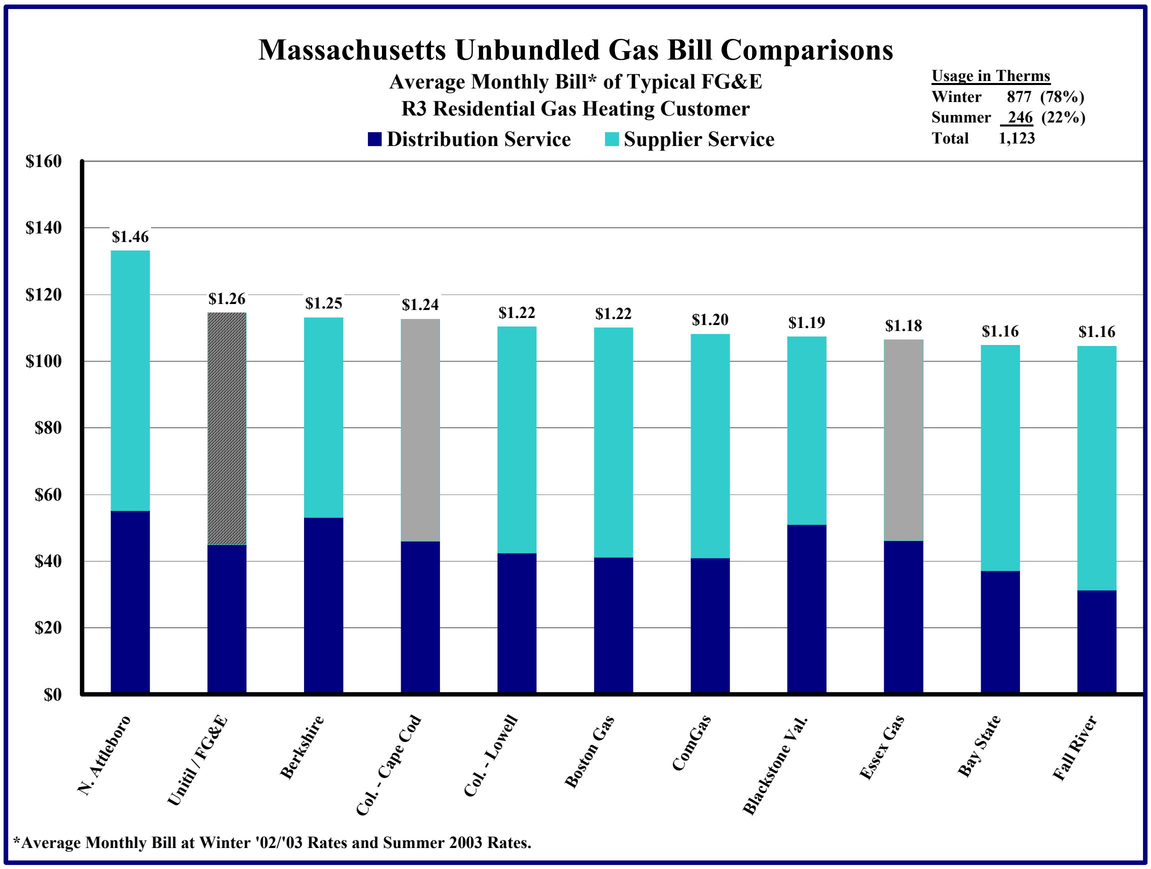
5. Maintain diversity of natural gas supplies through geological and geographical diversity of supply basins. This Guideline is demonstrated by FG&E's ability to purchase and receive gas through different supply points. The Company draws natural gas supplies from both the onshore and offshore supply basins of Alabama, Texas and Louisiana, as well as the market areas of the Appalachian supply basin and Eastern Massachusetts (receipt point for Sable Island Canadian supplies). This diversity provides security of supply in light of the potential for a variety of weather related supply disruptions, including the shut down of offshore wells as a result of tropical storm conditions or the curtailment of onshore supply delivery as a result of freeze-offs. In addition to the supply diversity within the Gulf Coast supply basin, the back-up for these supplies is located in the Appalachian supply. The Company's Appalachian supply basin, Eastern Massachusetts supply, underground storage entitlements and local production capability, taken as a whole, provide additional significant geographical diversity that mitigates the consequences of a Gulf Coast supply curtailment.

Maintain diversity of natural gas supplies through, limiting dependence on individual suppliers and limiting reliance on Canadian and other imported resources. This Guideline is further demonstrated by the diversity of suppliers in the Company's supply portfolio. The Company currently has six term contracts in place. There are also a number of base contracts under which FG&E can purchase supplies of gas. FG&E has and will continue to have contact with these suppliers on an as needed basis to procure supply. In the development of the Plan, risks associated with the operation and management of any particular resource is contained, with the use of non-price aspects such as (a) the supplier's financial position, (b) whether they are a producer or marketer, and (c) their ability to deliver gas to the Company's TGP receipt points. These planning considerations guard against over committing to low cost resource alternatives that may have higher risks, and also require that tradeoffs between risk and economics be made explicit in the decision making process.

6. Maintain costs within a competitive range. Figure 6 shows a typical bill comparison for a typical residential customer in the FG&E territory and in other LDC territories in Massachusetts. The data shown are representative of the average total gas costs for the time frame of November 1st 2002 through October 31st, 2003. As shown, FG&E's gas costs are consistent with the gas costs of the majority of LDCs in Massachusetts.

These competitive results were achieved with a strong and diverse supply portfolio that is responsive to a range of weather driven sendout requirements and is reasonably secure against supply disruptions. A discussion of analyses conducted to evaluate the adequacy of FG&E's supply portfolio under a range of weather driven sendout and operating conditions is provided in a subsequent section of this IRP.

Figure 6: Comparisons of Average Monthly Bills for Typical Residential Gas Heating Customers in Massachusetts (2002/2003)



7. Manage the risks of non-price related factors associated with gas supply and transportation contracts. This critical Guideline is an important part of supply contract negotiations. As stated above, the Company's achievement of this Guideline is evidenced by the terms and conditions that are a part of the Company's supply contracts associated with nominating flexibility, price caps, financial viability of suppliers, supply warranty provisions, etc. We have recently demonstrated the flexibility of FG&E's portfolio not only in the warm winter of 2001-02, but also in the near design winter of 2002-03. The Company was able to limit the takes of supply during the warm winter and had the ability to swing up or down on a given contract to meet these variant conditions.

8. Maintain local production capability to supplement pipeline supplies on peak winter days and to meet firm customer needs during the summer in the event of a pipeline failure. This Guideline is fulfilled by the Company's continued operation of its LNG and Propane-Air facilities. The Company's supplemental LNG and LPG supplies, coupled with firm pipeline supplies and underground storage, provide sufficient capacity to meet the peak day sendout as well as the design winter sendout requirements.

9. Seek to identify cost-effective alternative pipeline deliveries to reduce risk of failure of the interstate pipeline facilities serving the Company. Currently FG&E receives transportation to its city-gate only on the TGP system. The Company will consider proposals for new pipelines that offer delivery to the FG&E city-gate by weighing the cost of the proposed facility and the benefits to firm customers. As previously discussed, the Company has positioned its transportation contract portfolio in a way that will permit replacement in the longer term with alternatives that could include transportation on other interstate systems that interconnect with TGP. The Maritimes and Northeast Pipeline (M&NE) interconnects with the TGP system and that has allowed FG&E to replace 1618 Dth of TGP Gulf Coast and Niagara Transport with the TGP Zone 6 Transport at Dracut. This interconnection with M&NE provides access to Sable Island gas. However, ultimate delivery to the Company's city-gate will continue to be dependent on the Fitchburg lateral segment of the TGP system.

B. *APPLICATION OF RFP PROCESSES AND RESOURCE PLANNING GUIDELINES*

These Guidelines were most recently applied during the RFP processes conducted in May 2003. Design cold scenarios were analyzed for the winter season and for a single peak day assuming no customer migration. The mix of pipeline, storage, and peaking usage was determined using New Energy Associates Inc.'s SENDOUT® optimization model. The model's output helped the Company determine three key items;

1. Optimal peaking gas supplies;

2. Optimal additions to pipeline supplies for the winter months; and

3. Optimal storage withdrawal path.

Once the optimal mix of resources was determined, FG&E analysts worked with management and operational personnel to define additional flexibility and reliability contract requirements. While SENDOUT® is a useful optimization tool, it is not a substitute for the experience and judgment of the Company's employees, nor does it allow for variability in weather patterns or for pipeline restrictions that inevitably cause demand and supply forecasts to diverge. The impact of possible customer migration is also considered to determine what impact third party suppliers may have on the resource mix.

C. *SUPPLY PORTFOLIO*

With the current market conditions and the ability of customers to choose a third party natural gas supplier, FG&E has not made commitments longer than one year in duration for pipeline supplies. FG&E has completed an RFP process for one year supplies which required that the supplier have the ability to supply on the TGP system. FG&E has also completed an RFP for a one year and four year LNG supply for distribution system pressure needs during design winter conditions, because for the pressure need there is no alternative to LNG. This LNG supply may also be used to meet the peaking needs of the Company's customers. The contracts have been executed and the four year contract was filed with the Department on October 1, 2003 for review and approval.

An overview of FG&E's suppliers and supply contract terms is shown in Table 3.1. The current portfolio consists of two firm pipeline supplies, two underground storage agreements, a firm LNG supply agreement and an optional LPG contract. During the 2003/04 winter season FG&E also has two contracts for seasonal gas supply with Emera Energy Services Inc and NJR Energy Services Company representing an MDQ of 3,342 Dth.

Table 3.1: Supply and Storage Contract Summary (G-24a)

Contract	Terms	Type	MDQ	Expiration
Amerada Hess Corporation	Baseload/daily option	Pipeline	4000/2000*	10/31/2004
ConocoPhillips	Baseload/daily option	Pipeline	4288/2148*	10/31/2004
NJR Energy Service	Monthly nom/daily option	Pipeline	2258	3/31/2004
Emera Energy Service	Base load/ swing option	Pipeline	900/184	3/31/2004
TGP Firm Storage	4807 Daily Swing	Storage	4807	3/31/2008
Dominion Transmission	151 Day Storage	Storage	466	3/31/2004
Duke Energy Field Service	option 750,000 gallons	Peaking	3600	3/31/2004
DOMAC	Daily Call LNG limited to 27,500/yr	Peaking	1800	10/31/2004

*Winter/Summer

In addition FG&E has service agreements with many suppliers, which document commercial terms under which FG&E could purchase natural gas supply, as necessary and economic. The advantage of having service agreements in place with many suppliers is that FG&E can enter into transactions very quickly, since the non-price commercial terms are already agreed to in writing in advance of the negotiation to set the price of the transaction.

1. Pipeline Supplies:

The Company has a one-year contract with Amerada Hess Energy for up to 4000 Dth/day supply in the winter months and up to 2000 Dth/day in the summer. The Hess contract provides daily nominating flexibility. The contract term begins on November 1, 2003 and ends on October 31, 2004 with no explicit renewal terms.

The Company has a one-year contract with ConocoPhillips Company (Conoco) for up to 4288 Dth/day supply in the winter months and up to 2148 Dth/day in the summer. The Conoco contract is an asset management contract which provides a baseload and daily swing provision. The contract term begins on November 1, 2003 and ends on October 31, 2004 with no explicit renewal terms.

The Company has a winter contract with Emera Energy Services Inc (Emera), for up to 1084 Dth/day beginning December 1, 2003 and ending March 31, 2004. The Emera contract has a daily baseload volume of 900 Dth/day through this term and a daily swing quantity of 184 Dths. This contract is a zone 6 contract allowing the Company to access the M&NE Sable Island gas supplies.

A winter 2003-2004 contract was signed with NJR Energy Service Company for up to 2,258 Dth/day of supply from the Appalachian market area. The NJR contract provides base load supply with 1st of month nomination flexibility of 0 to 100 percent of the contract quantity. The contract term is from November 1, 2003 through March 31, 2004. Each year FG&E contracts for a supply such as this to ensure that its' underground storage does not get drawn down too quickly in the event of a design cold winter. An RFP for a similar contact is issued in the late spring of each year to obtain this seasonal supply.

2. Underground Storage:

The Company has a contract with TGP for underground storage having deliverability of up to 4807 Dth/day. This storage and associated transportation contracts have a termination date of March 31, 2008. These contracts were recently extended and included in the review and approval of the Company's TGP contract Restructuring Plan in Docket D.T.E. 02-85. The contract term will automatically extend for an additional 5-year term unless FG&E notifies TGP in writing prior to April 1, 2007.

The Company has a contract with Dominion Transmission Corporation (formerly CNG) for underground storage having deliverability of 466 Dth/day. The current contract renewal term commenced on April 1, 2000 and expires March 31, 2004. CNG gave its' intent to terminate the contract in March 2002, and FG&E affirmed the termination. The Company has found it is able to get significantly increased supply flexibility by having seasonal contracts with Appalachian suppliers to meet firm customer needs in the range of weather conditions experienced.

3. Local Production:

The Company operates an LNG storage and vaporization facility that is capable of delivering 7,200 Dth/day of sendout requirement. FG&E plans to continue providing LNG storage/vaporization capability, a portion of which is needed for system reliability in the form of pressure support. As mentioned previously, FGE has contracted for a four year supply of LNG, contingent upon MDTE approval. FG&E also owns a propane storage facility that is capable of delivering 10,573 Dth/day of sendout requirement. The compression for this plant was upgraded during the summer of 2003, increasing the vaporization from 7,200 Dth/day.

This upgrade did not require EFSC Approval based upon the level of increased compression capacity.

Prior to each winter season, FG&E purchases firm rights to enough LNG and propane in order to meet design cold winter conditions. The following steps are taken to calculate this amount. 1. A daily sendout requirement is calculated for each day of the upcoming winter, based on average historical weather patterns and the design cold winter monthly forecast. 2. The amount of firm Tennessee Gas Pipeline capability is summed, which is currently 14,057 Dth. 3. For each day of the upcoming winter, the daily sendout requirement is compared to the firm pipeline capability. If the daily sendout requirement exceeds the capability, then this amount of peaking resource is required for that day. 4. The daily peaking resource requirements are then summed. This sum is the peaking resource required by FG&E to reliably serve its customers under design winter conditions.

FG&E may fulfill this peaking requirement with either LNG or propane. There is some interchangeability between the two. However, FG&E requires a certain level of LNG for distribution system pressure support. Peaking supplies in excess of the LNG amounts required for pressure support are purchased based on the economics of LNG and propane as determined by the RFP bids. FG&E compares the cost of reserving LNG to the cost of reserving propane for the upcoming winter. Typically, LNG has a higher demand cost, but a lower commodity cost than propane. FG&E uses SENDOUT® supply optimization software, as well as its own business judgment, to evaluate the economics of these peaking supply options. A normal weather scenario is used for the economic analysis, since this is the expected scenario. The expected cost of LNG and propane are compared. FG&E purchases the least cost option for the balance of its peaking requirements

The Company has contracted for a winter supply of LPG with Duke Energy Field Services. This contract will supply up to 750,000 gallons (approximately 68,000 Dth) of LPG for the winter season of 2003-2004 with a deliverability of up to four trucks a day which equates to approximately 3,600 Dths. Additionally, the Company has an LPG storage inventory of 27,637 Dth as of October 22, 2003.

4. Pipeline Transport Services

The Company has contracted for TGP transportation service under the FERC-filed rate schedule FT-A and for storage service under rate schedule FS. Contract number 2273 represents the Firm Storage (FS) contract that FG&E has with TGP. FG&E also has an Operation Balancing Agreement (OBA) with TGP that, among other services, provides a no-notice daily demand service.

The Company's OBA provides a daily balancing and end of the month "true-up" mechanism for differences between total volumes nominated and actual sendout requirement. End of the month imbalances, within a set tolerance range, are "cashed out" in accordance with the TGP FERC tariff. The Company's OBA Daily Demand Service facilitates operations by providing flexibility comparable to the previously provided TGP contract demand service in that unforeseen sendout requirements may be met on a "no notice" basis. FG&E's existing pipeline service contracts are summarized in Table 3.2. This table reflects FG&E's recently approved TGP contract restructuring plan in D.T.E.02-85 as well as the TGP firm transportation agreement approved in D.T.E. 02-55 for contract 38927.

Table 3.2: Pipeline Contract Summary (G-24b)

Contract Number	Service Type	Capacity	Termination Date
267	FT-A	466	3/31/2008
268	FT-A	2795	3/31/2008
2273	FS-MA	N/A	3/31/2008
2374	FT-A	2012	3/31/2008
2915	FT-A	2104	3/31/2006
2916	FT-A	1466	3/31/2008
2919	FT-A	2000	3/31/2008
8519	FT-A	1596	3/31/2007
38927	FT-A	550	3/31/2007
42258	FT-A	534	3/31/2007
42812	FT-A	534	3/31/2007

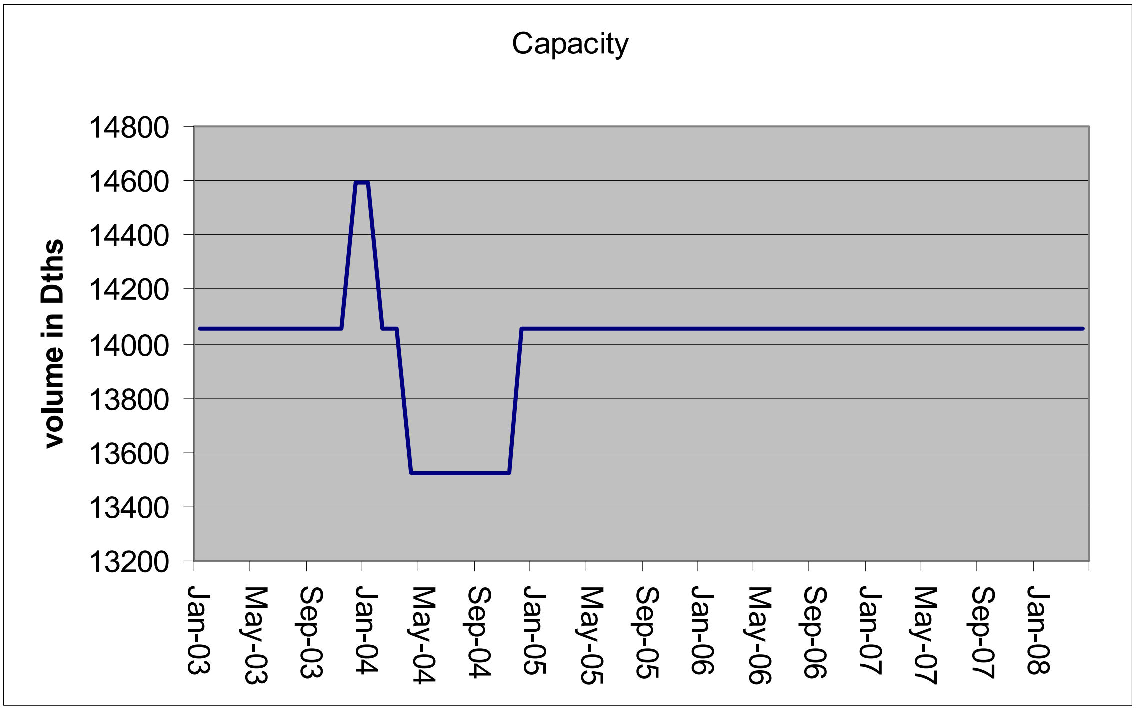
Contract 2915 has a maximum delivery of 2638 Dths/day until April 1, 2004 at which time it will be reduced to 2104 Dths/day. Contract 2916 has a maximum delivery of 2000 Dth's/day until February 1, 2004 at which time it will be reduced to 1466 Dth's/day.

Contracts 42258 and 42812 are new contracts each with a deliverability of 534 Dth's/day. Contract 42258 will begin on December 1, 2003, and contract 42812 will begin December 1, 2004.

Contracts 2915, 8519, 38927, 42258 and 42812 will have one more term election of the Company's choosing. All other contracts contain a right of first refusal for FG&E to extend the contracts.

As a result of the recent TGP restructuring, FG&E has contracted for a total Transportation capacity of 14,057 Dth/day. For the months of December 2003 and January 2004, the contracted capacity entitlement will be increased to 14,591 Dth/day which will reduce the Company's need for peaking supplies. Beginning on February 1, 2004 and continuing to March 31, 2004, the capacity contract entitlement is restored to 14,057 Dth/day at which time contract capacity reduces to 13,523 Dth/day through November 30, 2004. At that time FG&E will again have 14,057 Dth/day of TGP capacity. Table 3.21 depicts FG&E's Pipeline Capacity over time.

Figure 7: Pipeline Capacity resulting from recent TGP Restructuring



FG&E will be required to make renewal elections one year prior to the termination dates of each of the TGP contracts, with the next renewal date prior to March 31, 2005 for TGP contract 2915. Prior to each election date FG&E will conduct an analysis of its obligation to serve and at that time will go through a decision process similar to the process utilized in the recent restructuring plan approved in D.T.E. 02-85. If FG&E does not renew contract 2915, the total transportation capacity will be reduced to 11,953, beginning April 1, 2006. Prior to that date the Company will also be required to make renewal elections totaling 3,214 Dth/day on the following four separate contracts: 8519, 38927, 42258 and 42812.

D. *MARKETPLACE AND CONTRACTING ISSUES*

The marketplace for gas supplies is extremely competitive. During its seasonal contracting process, the Company has received responses to its Request for Proposals from up to half a dozen marketers who have pricing terms that are often within fractions of a penny of each other. The most common pricing terms are linked to widely published indices such as "Inside FERC" or "Gas Daily", and have a simple $/Dth adder on the index for a profit margin. This makes economic decision making very transparent and the analysis of pricing alternatives relatively straightforward.

Because of this pricing structure, new supply contracts have nearly identical pricing terms to their long-term predecessors. The only significant difference is in the demand charge. Demand charges are usually minimal or are not required when contracting for terms of one year or less. This makes short term contracting more cost effective. FG&E pays these minimal demand charges to ensure priority over spot purchasers and a commitment to be served by suppliers. Short term contracting allows the Company to adapt quickly to customer migration, and minimizes the cost shifting that would occur if fixed supply costs had to be allocated to customers who do not chose a competitive supplier. FG&E has primary firm transportation and suppliers therefore recognize that FG&E is positioned to take the gas contracted for and that the Company values the supplies enough to require firm delivery of our firm gas purchases from the suppliers.

As briefly discussed in the Pipeline Contract Summary, the Department recently approved in D.T.E. 02-85 a petition for approval of an implementation plan to restructure FG&E's TGP capacity contracts as well as for two new, Zone 6 capacity contracts (contract numbers 42258 and 42812). As discussed in the filing, FG&E took advantage of the renewal options available under the existing capacity contracts while transferring small increments of long-haul capacity to short-haul capacity where appropriate to improve the economics, diversity and flexibility of the portfolio. The Company decided to consider restructuring of these capacity contracts from long-haul to short-haul transportation contracts because the demand charges on short-haul transportation contracts are much lower than the demand charges on long-haul transportation contracts. The Company considered the difference in supply costs, the difference in transportation demand costs, the anticipated need for the supply on an annual basis, and the diversity of suppliers when making this decision.

Typically, Zone 6 supply is more expensive than the zone 1 and zone 0 supplies, which it was replacing. This is because Zone 6 is located in New England, where there is significant natural gas demand, and relatively little supply. Natural gas supply in Zone 1 and Zone 0 are typically lower, since most U.S. production of natural gas is located in that region. However, the demand cost of transportation capacity from Zone 1 and Zone 0 to Zone 6 is much higher than the demand cost of Zone 6 to Zone 6 transportation. The Company decided that savings could be achieved through a restructuring of the pipeline contracts because the increase in anticipated supply costs is more than offset by a decrease in pipeline demand charges.

This analysis was highly sensitive to the anticipated load factor of the supply. If the Company had required this supply throughout the year, the pipeline contract restructuring would have been uneconomic, since the Zone 0 and Zone 1 supply cost is much lower than the Zone 6 supply cost. The lower demand charges would not have offset the increased supply cost. However, FG&E identified that this capacity is needed primarily in the winter heating season. Because the capacity factor of some of the Gulf Coast pipeline transport and associated supply contracts was relatively low, significant savings could be achieved, since the demand cost of the short-haul capacity is much lower than that of long-haul capacity. Based on a weather-normalized demand, some of the Gulf Coast pipeline supply had a capacity factor of approximately 40 percent. At that capacity factor, the restructuring was economic, since the increase in supply cost was more than offset by the decrease in annual transportation costs.

The Company also determined that there is an adequate number of quality natural gas suppliers, who are able to provide the Zone 6 supply. The ability to call on different suppliers, including the ability to take advantage of the developing nearby Sable Island gas resources, will provide greater opportunities for cost effective gas purchases, and a reliable delivery for FG&E's firm customers.

E. *ANALYSIS OF RESOURCES UNDER NORMAL, DESIGN AND UNBUNDLING SCENARIOS*

1. Overview.

Uncertainty associated with the near term regulatory environment creates challenges in preparing a comprehensive resource acquisition plan. The following sections present the current resource mix assuming that all supply and the TGP storage contract is extended or replaced throughout the planning horizon at identical terms. As discussed in storage section, Dominion Transmission Storage will end March 31st 2004. As contracts expire, the Company's RFP process will be utilized and the Company will adhere to its stated Guidelines in ensuring the ability to reliably meet changing resource conditions in the most cost effective manner possible.

2. Design Standards

Throughput forecasts for a 1 in 30, 1 in 50, and 1 in 100 design year were analyzed to determine the adequacy of the Company’s design condition supply standards. The SENDOUT® software package by New Energy Associates was used to determine the cost implications of the different design scenarios. Table 3.3 summarizes the results.

Table 3.3: Incremental Supply Costs

Supply cost				
Year	change from 1 in 30 to 1 in 50		change from 1 in 30 to 1 in 100	
2003	$	78,400	$	158,600
2004	$	137,900	$	306,400
2005	$	132,800	$	298,600
2006	$	138,800	$	309,400
2007	$	142,100	$	313,800
Average	$	126,000	$	277,360

The cost of serving more stringent design scenarios increases because of increases in the variable costs of commodity and transportation. Peaking resources serve the majority of the incremental load. As shown in Table 3.3, the increase in supply costs associated with changing from a 1 in 30 year design standard to a 1 in 50 year design standard average $126,000 per year over the planning horizon, while changing the design planning standard from a 1 in 30 to a 1 in 100 year standard would require on average an additional $277,360. In addition, the cost involved in increasing the standard must be weighed against the small probability that the 1 in 30 occurrence would be exceeded. Furthermore, even in the event that the standard would be exceeded, operational problems would occur only if the entire propane air facility or the entire LNG peaking facility was unavailable, and no short term gas supplies were able to be purchased.

For these reasons, the Company believes that the extra costs associated with raising the design standard are not justified at this time for either the design year standard or the design day standard. The Company will continue to use the 1 in 30 year planning standard for its design day and design year criteria to satisfy customer needs in a least cost manner while meeting relatively stringent reliability standards.

3. Forecast of Resources Under Normal and Design Conditions

The adequacy of the FG&E's portfolio to meet normal and design conditions is shown in Tables 3.4 and 3.5. A cold snap analysis, demonstrating FG&E's ability to meet a ten day cold snap is also presented in the following section. The firm sendout requirements shown in Table 3.4 and Table 3.5 reflect the Low Firm Transportation assumption, which assumes that there will be no firm transportation over the forecast horizon, and firm sendout is therefore the same as firm throughput. Table 3.4 and Table 3.5 therefore demonstrate how FG&E can meet the highest expected sendout requirements over the planning horizon. As previously discussed, FG&E's resource portfolio planning process provides the flexibility to cost-effectively serve lower levels of sendout that may be associated with a heavily subscribed firm transportation program.. For this reason, FG&E has not presented an additional comparison of resources and requirements under differing assumptions about the level of firm transportation.

The firm sendout requirements shown in Table 3.4 and Table 3.5 also reflect the energy savings expected from FG&E's most recently filed energy efficiency programs. FG&E's energy efficiency programs are documented in D.T.E. 98-049 as filed on March 18, 2003. Page A-42 of the Appendix provides FG&E's throughput forecast, expected energy efficiency savings and net supply resource requirements over the forecast horizon.

The Company has extended its Tennessee Firm Storage contract, and the terms of all FG&E's supply contracts are on a yearly or winter only basis. Thus, every year FG&E will issue RFPs to meet the firm customer needs as well as any peaking support needed for the FG&E system. The RFPs will not only include a certain base load amount, but the ability to swing on a monthly or daily basis dependant on the weather conditions. FG&E uses its TGP storage as one option for variances in supply needs in conjunction with peaking supplies to meet both normal and design conditions. The Company's RFP process and Guidelines detailed earlier in this document will be used, given the pace of unbundling and other developments in the industry for procurement of resources.

Table 3.4: Comparison of Resources and Requirements - Normal Conditions (Table G-22N)

Resource Extension Option Scenario

	Normal Winter (MMbtu)					Normal Summer (MMBtu)				
	2002-03*	2003-04	2004-05	2005-06	2006-07	2003	2004	2005	2006	2007
Firm Sendout (Low FT)	1,807,296	1,640,061	1,643,175	1,632,559	1,620,647	757,591	752,350	746,017	736,771	728,738
Storage Refill	0	0	0	0	0	351,350	295,000	295,000	295,000	295,000
Total	1,807,296	1,640,061	1,643,175	1,632,559	1,620,647	1,108,941	1,047,350	1,041,017	1,031,771	1,023,738
Resources										
Boundary	40,050	0	0	0	0	0	0	0	0	0
Long Haul Supply 1	398,802	604,000	604,000	604,000	604,000	449,400	449,400	449,400	449,400	449,400
Long Haul Supply 2	616,568	377,500	377,500	377,500	377,500	428,000	428,000	428,000	428,000	428,000
Spot market	29,222	28,537	2,842	0	0	0	0	0	0	0
Zone 6 Spot	80,815	151,000	181,200	171,994	181,200	0	0	0	0	0
Storage	302,455	302,455	290,000	290,000	290,000	0	0	0	0	0
Zone 4 Supply	110,140	151,000	151,000	151,000	128,159	107,000	107,000	107,000	107,000	107,000
Peaking	101,476	25,569	36,633	38,065	39,788	0	0	0	0	0
Incremental Market Purchases	127,768	0	0	0	0	124,541	62,950	56,617	47,371	39,338
Total	1,807,296	1,640,061	1,643,175	1,632,559	1,620,647	1,108,941	1,047,350	1,041,017	1,031,771	1,023,738

*Using actual Winter 2002-03 Data.

Table 3.5: Comparison of Resources and Requirements - Design Conditions (Table G-22D)
Resource Extension Option Scenario

	Design Cold Winter (MMbtu)					Normal Summer (MMBtu)				
	2002-03*	2003-04	2004-05	2005-06	2006-07	2003	2004	2005	2006	2007
Firm Sendout (Low FT)	1,807,296	1,763,121	1,768,255	1,758,365	1,747,055	762,317	778,780	772,776	763,586	755,722
Storage Refill	0	0	0	0	0	351,350	295,000	295,000	295,000	295,000
Total	1,807,296	1,763,121	1,768,255	1,758,365	1,747,055	1,113,667	1,073,780	1,067,776	1,058,586	1,050,722
Resources										
Boundary	40,050	0	0	0	0	0	0	0	0	0
Long Haul Supply 1	398,802	604,000	604,000	604,000	604,000	449,400	449,400	449,400	449,400	449,400
Long Haul Supply 2	616,568	407,700	407,700	407,700	407,700	428,000	428,000	428,000	428,000	428,000
Spot market	29,222	24,251	29,502	14,590	0	0	0	0	0	0
Zone 6 Spot	80,815	181,200	181,200	181,200	180,562	0	0	0	0	0
Storage	302,455	302,455	290,000	290,000	290,000	0	0	0	0	0
Zone 4 Supply	110,140	151,000	151,000	151,000	151,000	107,000	107,000	107,000	107,000	107,000
Peaking	101,476	92,515	104,854	109,875	113,793	0	0	0	0	0
Incremental Market Purchases	127,768	0	0	0	0	129,267	89,380	83,376	74,186	66,322
Total	1,807,296	1,763,121	1,768,255	1,758,365	1,747,055	1,113,667	1,073,780	1,067,776	1,058,586	1,050,722

*Using actual Winter 2002-03 Data.

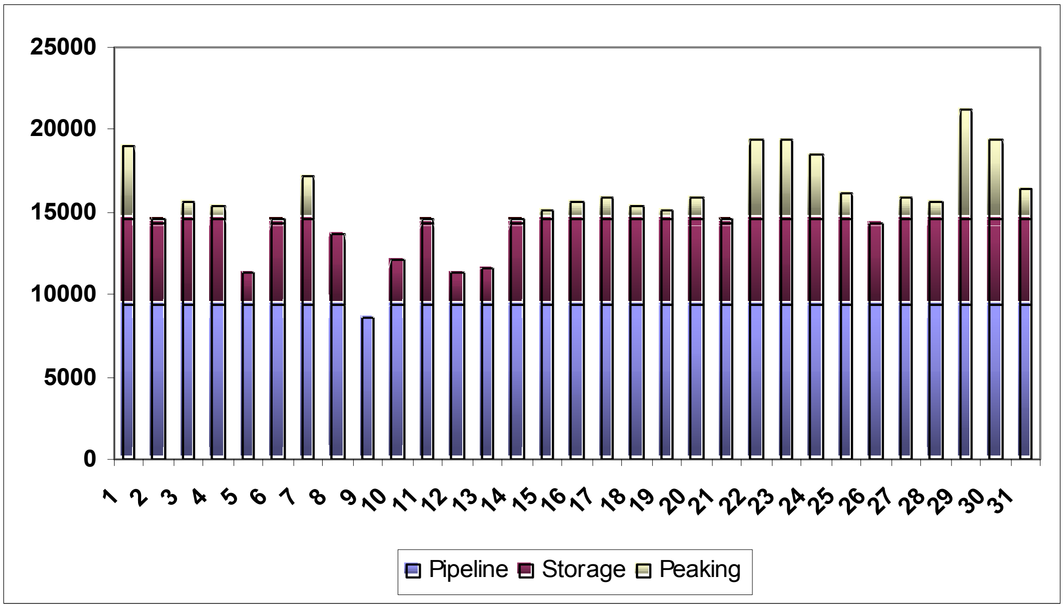
4. Cold Snap Analysis

An analysis was performed to assess the ability of FG&E's gas supplies to meet sendout requirements over ten consecutive extreme cold days. Historical weather data was reviewed and the sendout requirements associated with the ten consecutive coldest days over the past thirty years was used to model this scenario. That analysis assumed the cold snap would occur during the last ten days of an otherwise normal January since, in the context of a cold snap, the last ten days of January would pose the greatest challenge to the FG&E supply system.

There are a number of contingencies that could occur in either a cold snap and or design day that could challenge the reliability of FG&E's system. FG&E needs the LNG facility in order to keep line pressure above the minimum needed at the customers' meters. FG&E has installed a redundant system of boilers and vaporizers at this facility. FG&E plans to keep the LNG and LPG storage tanks at or near full throughout the winter season. Having firm receipt of these crucial peaking supplies as well as firm delivery to the TGP gate station of both the storage contract and other physical gas contracts, FG&E is able to meet the needs of its firm customers. If FG&E is unable to get trucking to the LNG facility for a number of days, there is the potential for a system interruption, however this contingency could be met by running the LNG facility at a minimum level for pressure support while running the LPG plant to meet the bulk of the peaking needs. Because FG&E has two peaking facilities which can be operated simultaneously, with the LNG facility running at minimum, FG&E has the necessary flexibility to maintain system reliability.

Figure 8 illustrates the daily sendout requirements and the expected gas supply dispatch for each day of the month in which the cold snap occurs. During this thirty one day period, pipeline supplies would be base loaded with underground storage and local production dispatched to meet specific daily sendout requirements. During the cold snap, a mixture of LNG and LPG supplies would be used to meet the peaking supply requirement. FG&E's gas supply portfolio would be capable of meeting sendout requirements for a ten-day end of the month cold snap with a reserve margin of approximately twenty five percent while only using one of the peaking plants.

Figure 8: Design January System Dispatch with a 10 Day Cold Snap



The dispatch of the company's portfolio during this scenario mirrors the behavior of the Company's supply portfolio dispatch under design cold conditions. The cumulative number of degree-days in a design cold January as forecasted is the same as the number of degree-days used to generate the cold snap analysis. The distribution of the degree-days is simply more concentrated in the last third of the month. Hence, the Company's supply portfolio is adequate in meeting both the design cold month and the more stringent cold snap criterion. The amount of peaking supply increases with a cold snap criterion because of the system profile, the total amount of gas needed is the same in both scenarios. On days over 14,057 Dths/day, needs are met with either LNG or Propane and as mentioned in the previous section a certain amount will be met with LNG system pressure support.

5. Design Day Analysis

Forecast and historic data has reached a level of approximately 22,000 Dth's on a design peak day. As with the comparison of resources and requirements for normal year and design year conditions, Table 3.6 presents design sendout requirements assuming the Low Firm Transportation scenario with peak day sendout assumed to equal FG&E's entire peak day throughput. FG&E meets this peak day requirement with pipeline supplies and local production, which total 31,830 Dth/day. FG&E has the ability to take 14,057 Dth/day of pipeline capacity at the city gate meter station and local production of 17,773 Dth/day. Prior to each winter heating season, FG&E matches its firm load obligations with firm supply arrangements in order to insure delivery of natural gas supply during peak days. As discussed in the Cold Snap Analysis, FG&E does need the LNG facility to meet the pressure requirements, which would occur on a design day. FG&E clearly has enough capacity to handle the design day scenario, even with partial availability of either the LNG or propane plants.

Table 3.6: Comparison of Resources and Requirements - Design Day (G-23)

Year	2003	2004	2005	2006	2007
Design Sendout (MMbtu)	22,025	22,133	22,241	22,349	22,457
Resources					
TGP Long haul supply	8,234	8,234	7,166	7,166	7,166
Boundary	534				
Zone 6 Spot	550	1,084	1,618	1,618	1,618
Storage	4,273	4,273	3,807	3,807	3,807
Zone 4 Supply	1,000	1,000	1,466	1,466	1,466
Peaking	7,434	7,542	8,184	8,292	8,400
Total	22,025	22,133	22,241	22,349	22,457

III. CONCLUSION

FG&E believes that the Company's long-range planning standards, demand forecasting methods and results, and design and normal sendout forecasts as presented herein are reviewable, appropriate and reliable and that it has presented a resource plan that will allow the Company to meet the requirements of it's firm customers in a least cost and reliable fashion. The Company further believes that it has complied with the Department's directive in its last IRP order in D.T.E. 00-42 relating to the development of the firm transportation forecast. Therefore, FG&E respectfully requests approval of the Integrated Gas Resource Plan presented herein.

Update of APPENDIX

Table of Contents

Standard Mass EFSC (4/86) Required Tables

Notes:

(1) Shaded exhibits have not changed since the original filing in May 2003.

(2) Page A-25A is a new page.

Table DD **Fitchburg Gas and Electric Light Company**

EFSC (4/86) Filed: October 2003

DEGREE DAY DATA

Split Year (11/1-10/31)	Heating Season	Non Heating Season	Total Split Year	Coldest Degree Day
1997-98	4,639	1,269	5,908	53
1998-99	4,650	1,436	6,086	57
1999-00	4,660	1,724	6,384	63
2000-01	5,425	1,427	6,852	57
2001-02	4,392	1,701	6,093	48
Normal Year	5,081	1,572	6,655	62
Design	5,641	1,854	7,283	71

	Time Period	Method Used	Recurrence Expectancy
Normal Year	35 Years	Normal Dist	N/A
Design Year	35 Years	Normal Dist	1 in 30
Design Day	35 Years	Normal Dist	1 in 30

Table FA **Fitchburg Gas and Electric Light Company**
EFSC (4/86) Filed: October 2003

FORECAST ACCURACY
Total Split-Year Normalized Firm Sendout
(Percent Difference)

Forecast Prepared for Three-Year Period Starting: 1999/00

Split Year (11/1-10/31)	Actual Normalized Sendout	1999-00	2000-01	2001-02
1999-00	2,391,379	2,455,273 2.67%		
2000-01	2,351,915		2,534,904 7.78%	
2001-02	2,300,414			2,631,204 14.38%

*SENDOUT BY CLASS***

TOTAL RESIDENTIAL CLASS (R-1, R-2, R-3 & R-4)

Historical Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	ACTUAL		NORMAL		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
1997-98	13,366	759,327	354,499	813,179	399,516	0.01030	22.48
1998-99	13,303	761,168	346,528	829,489	370,921	0.01030	20.59
1999-00	13,289	763,402	381,899	813,140	378,253	0.00986	23.23
2000-01	13,357	818,960	354,420	782,774	354,435	0.00965	21.73
2001-02	13,309	662,643	361,798	755,820	354,294	0.00898	22.24

Forecast Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	NORMAL		DESIGN		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
2002-03*	13,282	782,455	367,876	879,534	400,767	0.00961	22.40
2003-04	13,270	784,862	369,008	893,331	407,054	0.00964	22.40
2004-05	13,258	783,479	368,357	900,821	410,467	0.00960	22.40
2005-06	13,248	782,549	367,920	902,077	411,039	0.00956	22.40
2006-07	13,239	780,353	366,887	905,928	412,794	0.00949	22.40

** 2002-03 has 2 months of actual data and 10 months of forecast data.*
*** Values reported reflect Low FT Scenario, wherein all gas is supplied by FG&E.*

*SENDOUT BY CLASS***

SMALL COMMERCIAL & INDUSTRIAL (G-41 & G-51)

Historical Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	ACTUAL		NORMAL		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
1997-98	1,065	159,120	63,573	170,310	71,767	0.02457	63.95
1998-99	1,131	156,918	63,146	170,997	65,611	0.02191	61.18
1999-00	1,145	175,474	69,124	186,710	69,228	0.02540	51.50
2000-01	1,179	205,956	73,486	196,473	73,224	0.02686	53.08
2001-02	1,165	143,067	68,223	163,181	67,682	0.02118	52.26

Forecast Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	NORMAL		DESIGN		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
2002-03*	1,188	183,318	71,290	237,266	70,006	0.02435	52.28
2003-04	1,181	188,789	73,418	240,988	71,104	0.02551	52.28
2004-05	1,179	192,362	74,807	243,009	71,700	0.02619	52.28
2005-06	1,177	194,108	75,486	243,348	71,800	0.02657	52.28
2006-07	1,171	196,947	76,591	244,386	72,107	0.02725	52.28

** 2002-03 has 2 months of actual data and 10 months of forecast data.*
*** Values reported reflect Low FT Scenario, wherein all gas is supplied by FG&E.*

*SENDOUT BY CLASS***

MEDIUM & LARGE COMMERCIAL & INDUSTRIAL (G-42, G-52, G-43 & G-53)

Historical Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	ACTUAL		NORMAL		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
1997-98	283	589,463	330,576	624,135	361,903	0.43814	661.14
1998-99	266	556,072	312,442	589,787	335,165	0.42139	704.55
1999-00	270	602,371	343,903	642,632	335,482	0.43962	692.05
2000-01	279	682,888	319,322	652,923	335,292	0.42559	669.73
2001-02	293	525,786	324,400	597,270	323,680	0.37084	637.90

Forecast Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	NORMAL		DESIGN		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
2002-03*	291	624,785	342,183	644,109	328,920	0.39866	666.56
2003-04	289	643,401	352,825	654,213	334,079	0.41712	666.56
2004-05	288	656,786	360,308	659,698	336,880	0.43098	666.56
2005-06	287	660,709	362,643	660,618	337,350	0.43564	666.56
2006-07	287	669,068	367,575	663,438	338,790	0.44330	666.56

** 2002-03 has 2 months of actual data and 10 months of forecast data.*
*** Values reported reflect Low FT Scenario, wherein all gas is supplied by FG&E.*

*SENDOUT BY CLASS***
COMMERCIAL & INDUSTRIAL (G-41, G-51, G-42, G-52, G-43 & G-53)

Historical Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	ACTUAL		NORMAL		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
1997-98	1,348	748,583	394,149	794,445	433,671	0.08229	300.01
1998-99	1,397	712,989	375,588	760,784	400,776	0.07358	289.48
1999-00	1,415	777,845	413,027	829,342	404,710	0.08350	285.77
2000-01	1,458	888,843	392,808	849,396	408,517	0.09040	277.39
2001-02	1,459	668,854	392,623	760,451	391,362	0.06768	277.26

Forecast Period (MMbtus)

Split Year (11/1-10/31)	Average No. of Custs	NORMAL		DESIGN		Heat Use Per Cust Per DD	Base Load per Cust
		Heating Season	Non-Heating Season	Heating Season	Non-Heating Season		
2002-03*	1,479	808,103	413,473	881,375	398,926	0.08198	280.14
2003-04	1,470	832,190	426,243	895,201	405,184	0.08653	280.14
2004-05	1,467	849,148	435,115	902,707	408,581	0.08945	280.14
2005-06	1,464	854,817	438,129	903,966	409,151	0.09064	280.14
2006-07	1,458	866,015	444,166	907,825	410,897	0.09297	280.14

** 2002-03 has 2 months of actual data and 10 months of forecast data.*
*** Values reported reflect Low FT Scenario, wherein all gas is supplied by FG&E.*

*TOTAL COMPANY FIRM SENDOUT***

(includes Company Use and Lost and Unaccounted for Gas)

Split Year (11/1-10/31)	ACTUAL		NORMAL		Actual Peak Day
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season	
1997-98	1,513,551	750,905	1,607,624	833,187	16,007
1998-99	1,479,648	724,312	1,590,273	771,698	18,317
1999-00	1,547,087	797,262	1,642,482	782,963	20,956
2000-01	1,713,941	749,683	1,632,171	762,952	16,939
2001-02	1,336,711	756,507	1,516,272	745,656	16,542

Forecast Period (MMbtus)

Split Year (11/1-10/31)	NORMAL		DESIGN		Design Peak Day
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season	
2002-03*	1,618,480	795,066	1,760,909	799,693	22,025
2003-04	1,642,490	807,761	1,788,532	812,238	22,133
2004-05	1,655,465	814,712	1,803,527	819,048	22,241
2005-06	1,657,539	815,980	1,806,043	820,190	22,349
2006-07	1,664,017	819,748	1,813,753	823,692	22,457

** 2002-03 has 2 months of actual data and 10 months of forecast data.*
*** Values reported reflect Low FT Scenario, wherein all gas is supplied by FG&E.*

EXISTING GAS MANUFACTURING AND STORAGE FACILITIES (Mmbtu)

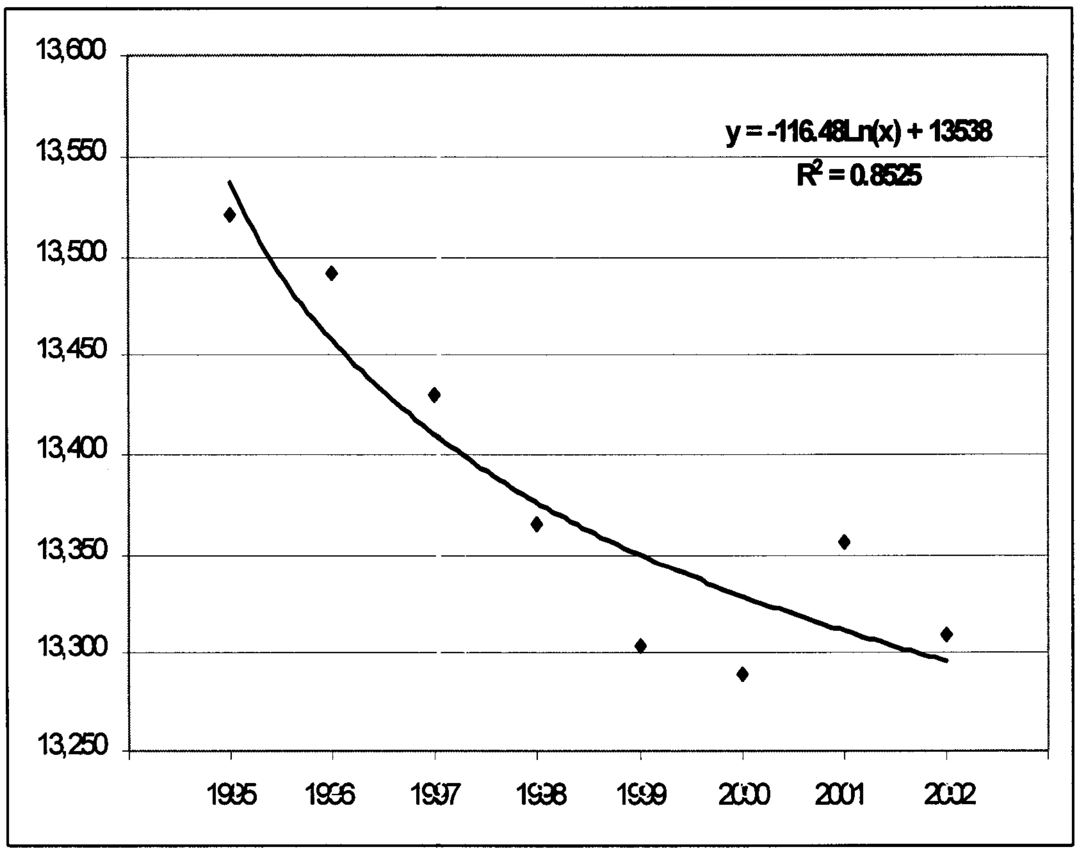
Type of Facility	Location	Anticipated Retirement Date	Last Actual Split Year Total Sendout (MMBtu)	Last Actual Split Year Max 24 Hr. Sendout (MMBtu)	Maximum Daily Desigh Capacity (MMBtu)	Storage Capacity in MMBtu
LNG Storage	Westminster, MA	None	25,012	1,977	7,200	4,556
Propane-Air	Lunenberg, MA	None	76,464	3,892	10,573	29,937

Curve Estimation for Residential Customers

MODEL: MOD_1. Fit of logarithmic equation.

Independent: Time

Dependent	Method	R Squared	d.f.	F	Sigf	b0	b1
RCUST	LOG	0.852	6	34.67	0.001	13537.8	-116.48



Regression Equation for Residential Volume

Model Description:

Variable: LRVOL
Regressors: LHHSIZE

95.00 percent confidence intervals will be generated.
Split group number: 1 Series length: 20
Number of cases skipped at end because of missing values: 6

Termination criteria:	Parameter epsilon: .001 Maximum number of iterations: 10
Initial values:	Estimate of Autocorrelation Coefficient Rho 0

Prais-Winsten Estimates:

Multiple R	0.71045575
R-Squared	0.50474738
Adjusted R-Squared	0.47723334
Standard Error	0.02636454
Durbin-Watson	0.84305602

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	1	0.0127515	0.0127515
Residuals	18	0.0125116	0.0006951

Variables in the Equation:

	B	SEB	BETA	T	SIG T
LHHSIZE	1.149002	0.268263	0.7104558	4.283117	0.0004475
CONSTANT	12.872338	0.2665266	.	48.296636	0.0000

Iteration History:

Iteration	Rho	SE Rho	DW	MSE
1	0.40407446	0.2218537	1.6480101	0.0005668
2	0.45016519	0.216571	1.7544648	0.0005565
3	0.46058448	0.2152785	1.7784464	0.0005544
4	0.46319593	0.2149486	1.7844474	0.0005539

Conclusion of estimation phase.
Estimation terminated at iteration number 5 because:
All parameter estimates changed by less than .001

Final Parameters using Prais Winsten correction for Autocorrelation

Estimate of Autocorrelation Coefficient:

Rho	0.46386655
Standard Error of Rho	0.21486354

Prais-Winsten Estimates:

Multiple R	0.54367217
R-Squared	0.29557943
Adjusted R-Squared	0.21270642
Standard Error	0.02353196
Durbin-Watson	1.7859877

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	1	0.0039501	0.0039501
Residuals	17	0.0094138	0.0005538

Variables in the Equation:

	B	SEB	BETA	T	SIG T
LHHSIZE	1.010348	0.3782907	0.5436722	2.670826	0.0161267
CONSTANT	13.006452	0.3761616	.	34.57677	0

The following new variables are being created:

Name	Label
FIT_7	Fit for LRVOL from AREG, MOD_4
ERR_7	Error for LRVOL from AREG, MOD_4
LCL_7	95% LCL for LRVOL from AREG, MOD_4
UCL_7	95% UCL for LRVOL from AREG, MOD_4
SEP_7	SE of fit for LRVOL from AREG, MOD_4

Correlations

		LRVOL	Fit for LRVOL from AREG, MOD_
LRVOL	Pearson Correlation	1	0.7905906
	Sig. (2-tailed)	.	3.342E-05
	N	20	20
Fit for LRVOL from AREG, MOD_4	Pearson Correlation	0.7905906	1
	Sig. (2-tailed)	3.342E-05	.
	N	20	20

** Correlation is significant at the 0.01 level (2-tailed).

R-Squared **0.625033572**

Regression Equations for Small Commercial and Industrial Customers

Model Summary(d)

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics					Durbin-Watson
					R Square Change	F Change	df1	df2	Sig. F Change	
1	0.972	0.944	0.941	0.0259837	0.944	305.458	1	18	0.000	
2	0.986	0.972	0.968	0.0191108	0.027	16.275	1	17	0.001	
3	0.991	0.982	0.979	0.0155597	0.011	9.645	1	16	0.007	1.750

a. Predictors: (Constant), LPOP
b. Predictors: (Constant), LPOP, LSVCEM
c. Predictors: (Constant), LPOP, LSVCEM, LTREND
d. Dependent Variable: LSCICUS

ANOVA(d)

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	0.206	1	0.206	305.458	0.000
	Residual	0.012	18	0.001		
	Total	0.218	19			
2	Regression	0.212	2	0.106	290.472	0.000
	Residual	0.006	17	0.000		
	Total	0.218	19			
3	Regression	0.215	3	0.072	295.341	0.000
	Residual	0.004	16	0.000		
	Total	0.218	19			

a. Predictors: (Constant), LPOP

Coefficients(a)

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-22.133	1.663		-13.310	0.000
	LPOP	2.157	0.123	0.972	17.477	0.000
	(Constant)	-42.783	5.263		-8.129	0.000
2	LPOP	4.140	0.500	1.865	8.282	0.000
	LSVCEM	-0.532	0.132	-0.909	-4.034	0.001
	(Constant)	-33.062	5.306		-6.231	0.000
3	LPOP	3.428	0.467	1.544	7.335	0.000
	LSVCEM	-0.551	0.108	-0.942	-5.126	0.000
	LTREND	0.049	0.016	0.368	3.106	0.007

a. Dependent Variable: LSCICUS

Residuals Statistics(a)

	Minimum	Maximum	Mean	Std. Deviation	N
Predicted Value	6.705933	7.080447	6.930736	0.1062544	20
Residual	-0.031551	0.018617	0.000000	0.0142786	20
Std. Predicted Value	-2.116	1.409	0.000	1.000	20
Std. Residual	-2.028	1.197	0.000	0.918	20

a. Dependent Variable: LSCICUS

Regression Equation for Small Commercial and Industrial Volumes

Variables Entered/Removed(a)

Model	Variables Entered	Variables Removed	Method
1	LSVCEM	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).
2	LDINCAP	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).

a. Dependent Variable: LSCIVOL

Model Summary(c)

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics					Durbin-Watson
					R Square Change	F Change	df1	df2	Sig. F Change	
1	0.962	0.926	0.922	0.0422867	0.926	226.576	1	18	0.000	
2	0.977	0.955	0.950	0.0339002	0.029	11.008	1	17	0.004	2.362

a. Predictors: (Constant), LSVCEM

b. Predictors: (Constant), LSVCEM, LDINCAP

c. Dependent Variable: LSCIVOL

ANOVA(c)

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	0.405	1	0.405	226.576	0.000
	Residual	0.032	18	0.002		
	Total	0.437	19			
2	Regression	0.418	2	0.209	181.777	0.000
	Residual	0.020	17	0.001		
	Total	0.437	19			

a. Predictors: (Constant), LSVCEM

b. Predictors: (Constant), LSVCEM, LDINCAP

c. Dependent Variable: LSCIVOL

Coefficients(a)

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	3.140	0.605		5.191	0.000
	LSVCEM	0.797	0.053	0.962	15.052	0.000
2	(Constant)	1.717	0.647		2.652	0.017
	LSVCEM	1.128	0.108	1.362	10.411	0.000
	LDINCAP	-0.743	0.224	-0.434	-3.318	0.004

a. Dependent Variable: LSCIVOL

Residuals Statistics(a)

	Minimum	Maximum	Mean	Std. Deviation	N
Predicted Value	12.012710	12.445498	12.242965	0.1482895	20
Residual	-0.051755	0.059125	0.000000	0.0320664	20
Std. Predicted Value	-1.553	1.366	0.000	1.000	20
Std. Residual	-1.527	1.744	0.000	0.946	20

a. Dependent Variable: LSCIVOL

Regression Equation for Medium Commercial and Industrial Customers

Model Description:

Variable: LMCICUS
Regressors: LMANEM

95.00 percent confidence intervals will be generated.
Split group number: 1 Series length: 20
No missing data.

Termination criteria:	Parameter epsilon: .001 Maximum number of iterations: 10
Initial values:	Estimate of Autocorrelation Coefficient Rho 0

Prais-Winsten Estimates:

Multiple R	0.80082331
R-Squared	0.64131798
Adjusted R-Squared	0.6213912
Standard Error	0.03762999
Durbin-Watson	0.75444158

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	1	0.04557267	0.04557267
Residuals	18	0.02548829	0.00141602

Variables in the Equation:

	B	SEB	BETA	T	SIG T
LMANEM	-0.646275	0.1139198	-0.8008233	-5.67307	0.00002216
CONSTANT	12.730563	1.2691344	.	10.030902	0

Iteration History:

Iteration	Rho	SE Rho	DW	MSE
1	0.5116519	0.20838487	1.4777855	0.00096935
2	0.59025912	0.19577811	1.5434215	0.00092164
3	0.61937596	0.19041339	1.5586821	0.00090503
4	0.63147173	0.18806186	1.5634549	0.00089827
5	0.63666505	0.18702903	1.5652155	0.00089538
6	0.63892137	0.18657588	1.5659259	0.00089413
7	0.63990632	0.18637721	1.5662257	0.00089359
8	0.64033713	0.18629015	1.5663548	0.00089335
9	0.64052573	0.18625201	1.566411	0.00089325

Conclusion of estimation phase.
Estimation terminated at iteration number 10 because:
All parameter estimates changed by less than .001

Final Parameters using Prais Winsten correction for Autocorrelation

Estimate of Autocorrelation Coefficient:

Rho	0.64060832
Standard Error of Rho	0.1862353

Prais-Winsten Estimates:

Multiple R	0.56649266
R-Squared	0.32091394
Adjusted R-Squared	0.24102146
Standard Error	0.02988645
Durbin-Watson	1.5664355

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	1	0.00717565	0.00717565
Residuals	17	0.0151844	0.0008932

Variables in the Equation:

	B	SEB	BETA	T	SIG T
LMANEM	-0.439291	0.1549874	-0.5664927	-2.8343687	0.01144575
CONSTANT	10.418804	1.7260775	.	6.0361156	0.00001336

The following new variables are being created:

Name	Label
FIT_18	Fit for LMCICUS from AREG, MOD_1
ERR_18	Error for LMCICUS from AREG, MOD_1
LCL_18	95% LCL for LMCICUS from AREG, MOD_1
UCL_18	95% UCL for LMCICUS from AREG, MOD_1
SEP_18	SE of fit for LMCICUS from AREG, MOD_1

Correlations

		LMCICUS	Fit for LMCICUS from AREG, MOD_1
LMCICUS	Pearson Correlation	1	0.86512395
	Sig. (2-tailed)	.	8.5102E-07
	N	20	20
Fit for LMCICUS from AREG, MOD_1	Pearson Correlation	0.86512395	1
	Sig. (2-tailed)	8.5102E-07	.
	N	20	20

** Correlation is significant at the 0.01 level (2-tailed).

R-Squared **0.748439441**

Regression Equation for Medium Commercial and Industrial Volume

Variables Entered/Removed(a)

Model	Variables Entered	Variables Removed	Method
1	LCGAS	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).
2	LSVCEM	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).
3	LDISINC	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).

a. Dependent Variable: LMCIVOL

Model Summary(d)

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics					Durbin-Watson
					R Square Change	F Change	df1	df2	Sig. F Change	
1	0.877	0.769	0.757	0.0553402	0.769	60.085	1	18	0.000	
2	0.931	0.867	0.852	0.0432310	0.098	12.496	1	17	0.003	
3	0.971	0.944	0.933	0.0290322	0.076	21.695	1	16	0.000	2.044

a. Predictors: (Constant), LCGAS
b. Predictors: (Constant), LCGAS, LSVCEM
c. Predictors: (Constant), LCGAS, LSVCEM, LDISINC
d. Dependent Variable: LMCIVOL

ANOVA(d)

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	0.184	1	0.184	60.085	0.000
	Residual	0.055	18	0.003		
	Total	0.239	19			
2	Regression	0.207	2	0.104	55.478	0.000
	Residual	0.032	17	0.002		
	Total	0.239	19			
3	Regression	0.226	3	0.075	89.239	0.000
	Residual	0.013	16	0.001		
	Total	0.239	19			

a. Predictors: (Constant), LCGAS
b. Predictors: (Constant), LCGAS, LSVCEM
c. Predictors: (Constant), LCGAS, LSVCEM, LDISINC
d. Dependent Variable: LMCIVOL

Coefficients(a)

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	15.529	0.322		48.200	0.000
	LCGAS	-0.552	0.071	-0.877	-7.751	0.000
2	(Constant)	11.082	1.283		8.639	0.000
	LCGAS	-0.318	0.086	-0.506	-3.691	0.002
	LSVCEM	0.297	0.084	0.485	3.535	0.003
3	(Constant)	5.293	1.512		3.500	0.003
	LCGAS	-0.226	0.061	-0.359	-3.684	0.002
	LSVCEM	0.985	0.158	1.607	6.230	0.000
	LDISINC	-0.878	0.188	-1.051	-4.658	0.000

a. Dependent Variable: LMCIVOL

Excluded Variables(d)

Model		Beta In	t	Sig.	Partial Correlation	Collinearity Statistics Tolerance
1	LHHOLD	0.461	3.195	0.005	0.613	0.406
	LPOP	0.405	2.872	0.011	0.572	0.459
	LNMANEM	0.311	2.061	0.055	0.447	0.477
	LSVCEM	0.485	3.535	0.003	0.651	0.415
	LTREND	0.423	2.288	0.035	0.485	0.304
	LDINCAP	0.187	1.320	0.204	0.305	0.610
	LDISINC	0.262	1.812	0.088	0.402	0.543
	LOUTPUT	0.083	0.716	0.483	0.171	0.980
2	LHHOLD	-0.328	-0.518	0.611	-0.128	0.020
	LPOP	-0.564	-1.159	0.264	-0.278	0.032
	LNMANEM	-0.739	-2.527	0.022	-0.534	0.069
	LTREND	-0.286	-0.875	0.394	-0.214	0.074
	LDINCAP	-0.725	-4.399	0.000	-0.740	0.138
	LDISINC	-1.051	-4.658	0.000	-0.759	0.069
	LOUTPUT	-0.301	-2.752	0.014	-0.567	0.471
3	LHHOLD	0.395	0.885	0.390	0.223	0.018
	LPOP	0.036	0.097	0.924	0.025	0.027
	LNMANEM	0.081	0.234	0.818	0.060	0.031
	LTREND	0.271	1.093	0.292	0.272	0.057
	LDINCAP	-0.066	-0.097	0.924	-0.025	0.008
	LOUTPUT	-0.097	-0.903	0.381	-0.227	0.307
a	Predictors in the Model: (Constant), LCGAS					
b	Predictors in the Model: (Constant), LCGAS, LSVCEM					
c	Predictors in the Model: (Constant), LCGAS, LSVCEM, LDISINC					
d	Dependent Variable: LMCIVOL					

Residuals Statistics(a)

	Minimum	Maximum	Mean	Std. Deviation	N
Predicted Value	12.870306	13.20599	13.033102	0.1089789	20
Residual	-0.045292	0.060196	0.000000	0.0266418	20
Std. Predicted Value	-1.494	1.586	0.000	1.000	20
Std. Residual	-1.560	2.073	0.000	0.918	20

a. Dependent Variable: LMCIVOL

Regression Equation for Lagre Commercial and Industrial Customers

Variables Entered/Removed(a)

Model	Variables Entered	Variables Removed	Method
1	LPOP	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).
2	LRESOIL	.	Stepwise (Criteria: Probability-of-F-to-enter <= .050, Probability-of-F-to-remove >= .100).

a. Dependent Variable: LLCICUS

Model Summary(c)

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
1	0.738	0.544	0.519	0.0650478	
2	0.836	0.699	0.663	0.0544343	1.628

a. Predictors: (Constant), LPOP

b. Predictors: (Constant), LPOP, LRESOIL

c. Dependent Variable: LLCICUS

ANOVA(c)

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	0.091	1	0.091	21.500	0.000
	Residual	0.076	18	0.004		
	Total	0.167	19			
2	Regression	0.117	2	0.058	19.703	0.000
	Residual	0.050	17	0.003		
	Total	0.167	19			

a. Predictors: (Constant), LPOP

b. Predictors: (Constant), LPOP, LRESOIL

c. Dependent Variable: LLCICUS

Coefficients(a)

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-16.373	4.163		-3.933	0.001
	LPOP	1.433	0.309	0.738	4.637	0.000
2	(Constant)	-21.380	3.875		-5.517	0.000
	LPOP	1.764	0.282	0.909	6.258	0.000
	LRESOIL	0.138	0.047	0.428	2.950	0.009

a. Dependent Variable: LLCICUS

Excluded Variables(c)

Model		Beta In	t	Sig.	Partial Correlation	Collinearity Statistics
						Tolerance
1	LHSTART	-0.033	-0.176	0.863	-0.043	0.768
	LHHSIZE	1.204	2.091	0.052	0.452	0.064
	LHHOLD	-3.756	-2.091	0.052	-0.452	0.007
	LNMANEM	-0.386	-0.770	0.452	-0.184	0.103
	LSVCEM	-0.730	-0.826	0.420	-0.196	0.033
	LMANEM	-0.070	-0.207	0.839	-0.050	0.232
	LTREND	-1.207	-2.397	0.028	-0.503	0.079
	LDINCAP	0.167	0.406	0.690	0.098	0.157
	LDISINC	0.253	0.406	0.690	0.098	0.068
	LOUTPUT	0.275	1.524	0.146	0.347	0.725
	LRESOIL	0.428	2.950	0.009	0.582	0.841
2	LHSTART	0.015	0.094	0.926	0.024	0.759
	LHHSIZE	0.730	1.319	0.206	0.313	0.055
	LHHOLD	-2.277	-1.319	0.206	-0.313	0.006
	LNMANEM	-0.296	-0.699	0.494	-0.172	0.102
	LSVCEM	-1.383	-1.970	0.066	-0.442	0.031
	LMANEM	-0.350	-1.225	0.238	-0.293	0.211
	LTREND	-0.480	-0.735	0.473	-0.181	0.043
	LDINCAP	0.041	0.118	0.908	0.029	0.155
	LDISINC	0.062	0.118	0.908	0.029	0.067
	LOUTPUT	0.049	0.258	0.800	0.064	0.529

a Predictors in the Model: (Constant), LPOP
b Predictors in the Model: (Constant), LPOP, LRESOIL
c Dependent Variable: LLCICUS

Residuals Statistics(a)

	Minimum	Maximum	Mean	Std. Deviation	N
Predicted Value	2.819435	3.100276	2.930953	0.0783923	20
Residual	-0.126090	0.125386	0.000000	0.0514897	20
Std. Predicted Value	-1.423	2.160	0.000	1.000	20
Std. Residual	-2.316	2.303	0.000	0.946	20

a. Dependent Variable: LLCICUS

Regression Equation for Large Commercial and Industrial Volume

Model Description:

Variable: LLCIVOL
Regressors: LSVCEM, LDISINC

95.00 percent confidence intervals will be generated.
Split group number: 1 Series length: 20
No missing data.

Termination criteria:	Parameter epsilon: .001 Maximum number of iterations: 10
Initial values:	Estimate of Autocorrelation Coefficient Rho 0

Prais-Winsten Estimates:

Multiple R	0.94731485
R-Squared	0.89740543
Adjusted R-Squared	0.88533548
Standard Error	0.071613
Durbin-Watson	0.92597123

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	2	0.76260038	0.38130019
Residuals	17	0.08718318	0.00512842

Variables in the Equation:

	B	SEB	BETA	T	SIG T
LSVCEM	2.2121204	0.3224179	1.9157635	6.86103	0.00000276
LDISINC	-1.6642482	0.4396465	-1.0569801	-3.78542	0.00147685
CONSTANT	-7.7953258	2.5123033	.	-3.10286	0.00646479

Iteration History:

Iteration	Rho	SE Rho	DW	MSE
1	0.53011779	0.211981	1.6867769	0.00381
2	0.57240098	0.20499346	1.7377119	0.0038
3	0.58252259	0.20320363	1.7490167	0.0038
4	0.58526437	0.20271063	1.7520168	0.0038
5	0.58602999	0.20257234	1.7528497	0.0038
6	0.58624555	0.20253335	1.7530838	0.0038

Conclusion of estimation phase.
Estimation terminated at iteration number 7 because:
All parameter estimates changed by less than .001

Final Parameters using Prais Winsten correction for Autocorrelation

Estimate of Autocorrelation Coefficient:

Rho	0.58630639
Standard Error of Rho	0.20252235

Prais-Winsten Estimates:

Multiple R	0.85276041
R-Squared	0.72720031
Adjusted R-Squared	0.67605037
Standard Error	0.06160426
Durbin-Watson	1.7531499

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	2	0.16186454	0.08093227
Residuals	16	0.06072137	0.00379509

Variables in the Equation:

	B	SEB	BETA	T	SIG T
LSVCEM	1.8880804	0.4721632	1.656962	3.99879	0.00103466
LDISINC	-1.279106	0.5900058	-0.8983271	-2.16796	0.04558686
CONSTANT	-5.1801599	3.8457582	.	-1.34698	0.19675615

The following new variables are being created:

Name	Label
FIT_4	Fit for LLCIVOL from AREG, MOD_3
ERR_4	Error for LLCIVOL from AREG, MOD_3
LCL_4	95% LCL for LLCIVOL from AREG, MOD_3
UCL_4	95% UCL for LLCIVOL from AREG, MOD_3
SEP_4	SE of fit for LLCIVOL from AREG, MOD_3

Correlations

		LLCIVOL	Fit for LLCIVOL from AREG, MOD_3
LLCIVOL	Pearson Correlation	1	0.96418184
	Sig. (2-tailed)	.	8.0919E-12
	N	20	20
Fit for LLCIVOL from AREG, MOD_3	Pearson Correlation	0.964181837	1
	Sig. (2-tailed)	8.09192E-12	.
	N	20	20

** Correlation is significant at the 0.01 level (2-tailed).

R-squared **0.929646615**

Peak Day Regression Output

Variables Entered/Removed(b,c)

Model	Variables Entered	Variables Removed	Method
1	TREND, PEAKHDD(a)	.	Enter

a. All requested variables entered.
b. Dependent Variable: PEAKVOL
c. Linear Regression through the Origin

Model Summary(c,d)

Model	R	R Square(a)	Adjusted R Square	Std. Error of the Estimate	Durbin-Watson
1	0.999	0.998	0.998	774.727738	1.736

a. For regression through the origin (the no-intercept model), R Square measures the proportion of the variability in the
b. Predictors: TREND, PEAKHDD
c. Dependent Variable: PEAKVOL
d. Linear Regression through the Origin

ANOVA(c,d)

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	6,436,158,564.775	2	3,218,079,282.39	5,361.651	0.000
	Residual	10,803,655.225	18	600,203.07		
	Total	6,446,962,220.000	20			

a. Predictors: TREND, PEAKHDD
b. This total sum of squares is not corrected for the constant because the constant is zero for regression through the origin.
c. Dependent Variable: PEAKVOL
d. Linear Regression through the Origin

Coefficients(a,b)

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	PEAKHDD	279.284	5.595	0.937	49.913	0.000
	TREND	107.951	28.127	0.072	3.838	0.001

a. Dependent Variable: PEAKVOL
b. Linear Regression through the Origin

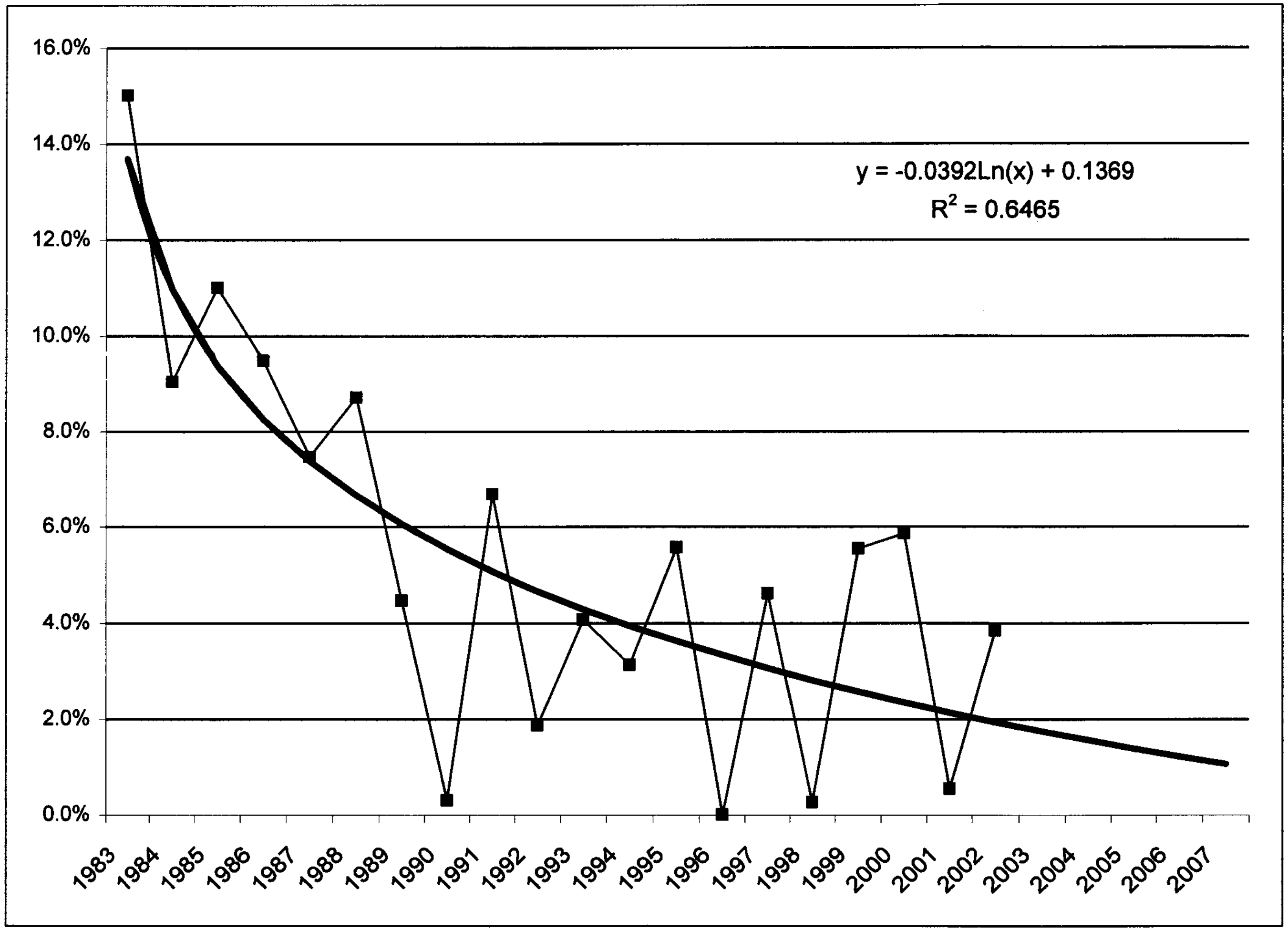
Residuals Statistics(a,b)

	Minimum	Maximum	Mean	Std. Deviation	N
Predicted Value	15,691.393555	19,728.126953	17,904.462669	1,141.626162	20
Residual	-1,283.572021	1,418.018555	2.73733116	754.059378	20
Std. Predicted Value	-1.939	1.597	0.000	1.000	20
Std. Residual	-1.657	1.830	0.004	0.973	20

a. Dependent Variable: PEAKVOL
b. Linear Regression through the Origin

Projection of Company Use and Lost and Unaccounted For Percentages

	% Difference Throughput vs. Deliveries	Predicted %
1983	15.02%	13.7%
1984	9.05%	11.0%
1985	11.01%	9.4%
1986	9.48%	8.3%
1987	7.47%	7.4%
1988	8.71%	6.7%
1989	4.47%	6.1%
1990	0.31%	5.5%
1991	6.68%	5.1%
1992	1.88%	4.7%
1993	4.07%	4.3%
1994	3.14%	3.9%
1995	5.57%	3.6%
1996	0.01%	3.3%
1997	4.62%	3.1%
1998	0.28%	2.8%
1999	5.55%	2.6%
2000	5.86%	2.4%
2001	0.56%	2.1%
2002	3.85%	1.9%
2003		1.8%
2004		1.6%
2005		1.4%
2006		1.2%
2007		1.1%



* Pursuant to the Staff's First Set of Information Requests, the above data is responsive to DTE 1-33 (a)

Fitchburg Gas and Electric Light Company
Analysis of Worcester/Bedford Weather Data
Design Cold Daily Degree Days Analysis

Description	Max	Avg Max	Std Dev	Count
	<----- 35 Year Averages ----->			
Annual Degree Days	73	62.0	4.8	35
t-statistic (95% Confidence Level) =		2.035		
DESIGN COLD				
1 in 20 DESIGN DAY		70		
1 in 30 DESIGN DAY		71		
1 in 40 DESIGN DAY		71		
1 in 50 DESIGN DAY		72		
1 in 100 DESIGN DAY		73		

Fitchburg Gas and Electric Light Company
Analysis of Worcester/Bedford Weather Data
Design Cold Daily Degree Days Analysis
Monthly Data

Description	Max	Avg Max	Std Dev	Count
	<----- 35 Year Averages ----->			
January	70	59.03	6.72	35
February	67	55.69	5.33	35
March	54	45.89	4.76	35
April	47	32.40	4.62	35
May	29	21.23	3.77	35
June	18	12.09	3.32	35
July	10	4.20	2.59	35
August	14	7.23	3.59	35
September	28	17.57	3.52	35
October	36	28.80	4.04	35
November	50	40.40	4.34	35
December	73	54.14	5.84	35
Maximum	73	61.97	4.78	35

Fitchburg Gas and Electric Light Company
Normal and Design Year Throughput, DSM Savings and Supply Resource Requirements (Dth)

	Normal Year Conditions			Design Year Conditions		
Period	Throughput Forecast	Energy Efficiency (DSM)	Supply Resource Requirements (net of DSM)	Throughput Forecast	Energy Efficiency (DSM)	Supply Resource Requirements (net of DSM)
Nov-02	236,338	0	236,338	252,152	0	252,152
Dec-02	348,921	0	348,921	375,826	0	375,826
Jan-03	405,786	0	405,786	436,765	0	436,765
Feb-03	345,298	0	345,298	370,034	0	370,034
Mar-03	303,966	0	303,966	325,740	0	325,740
Apr-03	190,326	0	190,326	202,033	0	202,033
May-03	116,823	1,260	115,564	120,749	1,260	119,489
Jun-03	79,814	717	79,097	80,460	717	79,743
Jul-03	66,239	598	65,641	66,283	598	65,685
Aug-03	69,954	542	69,412	70,045	542	69,503
Sep-03	83,935	628	83,306	85,413	628	84,784
Oct-03	155,225	981	154,244	163,155	981	162,174
Nov-03	240,380	3,910	236,471	256,575	3,910	252,665
Dec-03	355,799	5,076	350,723	383,351	5,076	378,275
Jan-04	413,518	8,074	405,445	445,227	8,074	437,153
Feb-04	351,472	7,282	344,190	376,790	7,282	369,508
Mar-04	309,401	6,168	303,233	331,687	6,168	325,519
Apr-04	193,248	4,632	188,616	205,231	4,632	200,599
May-04	117,803	3,145	114,658	121,821	3,145	118,676
Jun-04	79,975	1,792	78,183	80,637	1,792	78,845
Jul-04	66,250	1,489	64,761	66,295	1,489	64,806
Aug-04	69,977	1,348	68,629	70,070	1,348	68,722
Sep-04	84,303	1,566	82,738	85,816	1,566	84,250
Oct-04	157,205	2,439	154,765	165,321	2,439	162,881
Nov-04	244,422	6,252	238,170	260,998	6,252	254,746
Dec-04	362,676	8,121	354,555	390,877	8,121	382,756
Jan-05	417,716	12,918	404,798	449,820	12,918	436,902
Feb-05	354,824	11,655	343,169	380,458	11,655	368,803
Mar-05	312,351	9,868	302,483	334,916	9,868	325,048
Apr-05	194,834	7,411	187,423	206,967	7,411	199,555
May-05	118,335	5,030	113,305	122,403	5,030	117,373
Jun-05	80,063	2,867	77,196	80,732	2,867	77,866
Jul-05	66,256	2,380	63,876	66,302	2,380	63,921
Aug-05	69,989	2,154	67,835	70,083	2,154	67,929
Sep-05	84,504	2,504	82,000	86,035	2,504	83,532
Oct-05	158,279	3,898	154,381	166,497	3,898	162,599
Nov-05	246,617	8,595	238,022	263,400	8,595	254,805
Dec-05	366,409	11,165	355,244	394,962	11,165	383,797
Jan-06	418,420	17,762	400,658	450,591	17,762	432,828
Feb-06	355,386	16,027	339,359	381,073	16,027	365,046
Mar-06	312,846	13,569	299,277	335,458	13,569	321,889
Apr-06	195,100	10,191	184,910	207,258	10,191	197,067
May-06	118,424	6,915	111,509	122,501	6,915	115,586
Jun-06	80,078	3,942	76,136	80,749	3,942	76,807
Jul-06	66,257	3,272	62,986	66,303	3,272	63,031
Aug-06	69,991	2,959	67,032	70,085	2,959	67,126
Sep-06	84,537	3,441	81,096	86,072	3,441	82,631
Oct-06	158,459	5,356	153,103	166,694	5,356	161,338

Fitchburg Gas and Electric Light Company
Normal and Design Year Throughput, DSM Savings and Supply Resource Requirements (Dth)

	Normal Year Conditions			Design Year Conditions		
Period	Throughput Forecast	Energy Efficiency (DSM)	Supply Resource Requirements (net of DSM)	Throughput Forecast	Energy Efficiency (DSM)	Supply Resource Requirements (net of DSM)
Nov-06	246,985	10,938	236,047	263,803	10,938	252,865
Dec-06	367,035	14,210	352,825	395,648	14,210	381,438
Jan-07	420,578	22,607	397,972	452,953	22,607	430,346
Feb-07	357,110	20,400	336,710	382,959	20,400	362,559
Mar-07	314,363	17,269	297,094	337,118	17,269	319,848
Apr-07	195,916	12,970	182,946	208,150	12,970	195,180
May-07	118,698	8,800	109,898	122,800	8,800	114,000
Jun-07	80,123	5,017	75,105	80,798	5,017	75,781
Jul-07	66,260	4,163	62,098	66,306	4,163	62,143
Aug-07	69,997	3,765	66,232	70,092	3,765	66,327
Sep-07	84,640	4,379	80,261	86,185	4,379	81,806
Oct-07	159,012	6,814	152,197	167,298	6,814	160,484
Nov-07	248,113	13,281	234,833	265,037	13,281	251,757
Dec-07	368,955	17,255	351,700	397,748	17,255	380,493
	A			B		
Cal Yr 2003	2,413,545	13,711	2,399,834	2,560,603	13,711	2,546,892
Cal Yr 2004	2,450,251	52,307	2,397,943	2,600,770	52,307	2,548,462
Cal Yr 2005	2,470,177	80,445	2,389,732	2,622,575	80,445	2,542,130
Cal Yr 2006	2,473,520	108,582	2,364,938	2,626,233	108,582	2,517,651
Cal Yr 2007	2,483,765	136,719	2,347,046	2,637,445	136,719	2,500,725
Gas Yr 02/03	2,402,626	4,726	2,397,900	2,548,654	4,726	2,543,928
Gas Yr 03/04	2,439,331	46,920	2,392,411	2,588,821	46,920	2,541,901
Gas Yr 04/05	2,464,249	75,057	2,389,192	2,616,088	75,057	2,541,031
Gas Yr 05/06	2,472,525	103,195	2,369,331	2,625,145	103,195	2,521,950
Gas Yr 06/07	2,480,717	131,332	2,349,385	2,634,109	131,332	2,502,777
Win 02/03	1,640,309	0	1,640,309	1,760,516	0	1,760,516
			C			D
Win 03/04	1,670,570	30,509	1,640,061	1,793,630	30,509	1,763,121
Win 04/05	1,691,989	48,814	1,643,175	1,817,069	48,814	1,768,255
Win 05/06	1,699,678	67,119	1,632,559	1,825,484	67,119	1,758,365
Win 06/07	1,706,071	85,424	1,620,648	1,832,479	85,424	1,747,056
Sum 03	762,317	4,726	757,591	788,138	4,726	783,412
Sum 04	768,761	16,411	752,351	795,190	16,411	778,780
Sum 05	772,260	26,243	746,017	799,019	26,243	772,776
Sum 06	772,847	36,076	736,771	799,661	36,076	763,586
Sum 07	774,646	45,908	728,738	801,630	45,908	755,722

Notes:

A - These data are reported on Table 2.40, Firm Sendout Forecast by FT Scenario.

B - These data are reported on Table 2.42, Design Cold (1 in 30) Year Firm Sendout.

C - These data are repored on Table 3.4, Comparison of Resources and Requirements (G-22N).

D - These data are repored on Table 3.5, Comparison of Resources and Requirements (G-22D).